



STRENGTH
IN OUR RESOURCES

PETROBANK ENERGY AND RESOURCES LTD. IS A CALGARY-BASED OIL AND NATURAL GAS EXPLORATION AND PRODUCTION COMPANY WITH OPERATIONS IN WESTERN CANADA AND COLOMBIA. THE COMPANY OPERATES HIGH-IMPACT PROJECTS THROUGH THREE BUSINESS UNITS. THE CANADIAN BUSINESS UNIT IS DEVELOPING A SOLID PRODUCTION PLATFORM FROM LOW RISK GAS OPPORTUNITIES IN CENTRAL ALBERTA, ALONG WITH A LIGHT OIL RESOURCE PLAY IN SOUTHEAST SASKATCHEWAN, COMPLEMENTED BY NEW EXPLORATION PROJECTS AND A LARGE UNDEVELOPED LAND BASE. THE LATIN AMERICAN BUSINESS UNIT IS OPERATED BY PETROBANK'S 80.7 PERCENT OWNED, TSX-LISTED SUBSIDIARY, PETROMINERALES LTD. (TRADING SYMBOL: PMG), WHICH PRODUCES OIL THROUGH TWO INCREMENTAL PRODUCTION CONTRACTS IN COLOMBIA AND HAS EXPLORATION CONTRACTS COVERING 1.5 MILLION ACRES IN THE LLANOS AND PUTUMAYO BASINS. WHITESANDS INSITU LTD., PETROBANK'S 84 PERCENT OWNED SUBSIDIARY, OWNS 39,680 ACRES OF OIL SANDS LEASES WITH AN ESTIMATED 2.6 BILLION BARRELS OF BITUMEN-IN-PLACE AND OPERATES THE WHITESANDS PROJECT WHICH IS FIELD-DEMONSTRATING PETROBANK'S PATENTED THAI™ HEAVY OIL RECOVERY PROCESS. THAI™ IS AN EVOLUTIONARY IN-SITU COMBUSTION TECHNOLOGY FOR THE RECOVERY OF BITUMEN AND HEAVY OIL THAT INTEGRATES EXISTING PROVEN TECHNOLOGIES AND PROVIDES THE OPPORTUNITY TO CREATE A STEP CHANGE IN THE DEVELOPMENT OF HEAVY OIL RESOURCES GLOBALLY.

2006 WAS A BREAK-OUT YEAR FOR EACH OF PETROBANK'S THREE BUSINESS UNITS. AT OUR WHITE-SANDS PROJECT WE INITIATED THE WORLD'S FIRST THAI™ PRODUCTION AND CONTINUED TO EXPAND OUR OIL SANDS RESOURCE BASE, NOW ESTIMATED AT 2.6 BILLION BARRELS OF BITUMEN-IN-PLACE. IN SOUTH-EAST SASKATCHEWAN, WE HAVE ESTABLISHED THE COMPANY AS ONE OF THE PREMIER BAKKEN LIGHT OIL PLAYERS, AND IN COLOMBIA, WE MORE THAN DOUBLED PRODUCTION AND COMPLETED THE PETROMINERALES IPO.

ANNUAL GENERAL MEETING

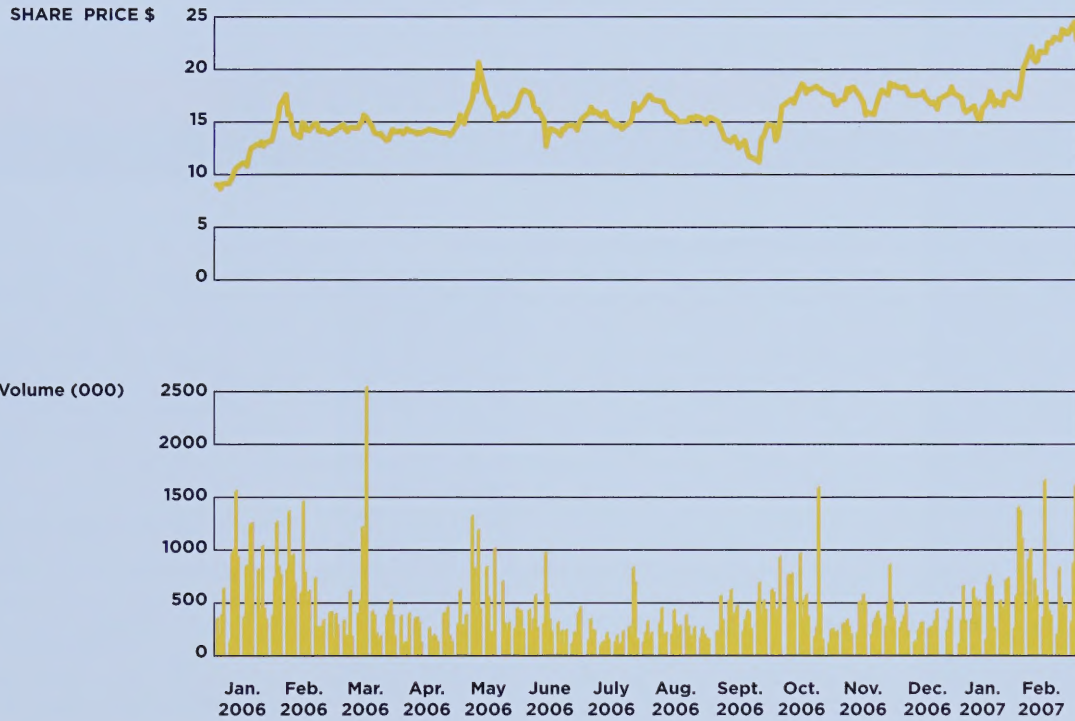
The Annual General Meeting of shareholders will be held on Tuesday, May 15, 2007 at 3:00 pm in the Lecture Theatre of the Metropolitan Conference Centre, Calgary, Alberta, Canada.

All shareholders are cordially invited and encouraged to attend.

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SHARE TRADING (TSX:PBG)



**STRENGTH
IN THE MARKET**

HIGHLIGHTS

(Throughout this report references to \$ are Canadian dollars unless otherwise noted)

(\$000s, except where noted)	2006	2005	% change
Financial			
Oil and natural gas revenue	99,228	65,081	52
Funds flow from operations ⁽¹⁾	61,425	29,152	111
Per share – basic (\$)	0.92	0.50	84
Per share – diluted (\$)	0.89	0.49	82
Net income	23,106	12,808	80
Per share – basic (\$)	0.35	0.22	59
Per share – diluted (\$)	0.33	0.21	57
Capital expenditures	229,693	118,152	94
Net debt ⁽²⁾	40,545	60,808	(33)
Common shares outstanding, end of year (000s)			
Basic	72,125	63,220	14
Diluted	76,538	68,451	12
Operations ⁽³⁾			
Canadian operating netback (\$/boe except where noted)			
Oil and NGL revenue (\$/bbl) ⁽⁴⁾	61.18	60.96	-
Natural gas revenue (\$/mcf) ⁽⁴⁾	6.21	8.09	(23)
Oil and natural gas revenue ⁽⁴⁾	44.40	50.84	(13)
Royalties	6.28	10.46	(40)
Production expenses	6.89	6.05	14
Transportation expenses	0.39	0.98	(60)
Operating netback	30.84	33.35	(8)
Colombian operating netback (\$/bbl)			
Oil revenue	61.68	53.62	15
Royalties	4.95	4.29	15
Production expenses	7.78	9.49	(18)
Operating netback	48.95	39.84	23
Average daily production			
Canada – oil and NGL (bbls)	918	452	103
Canada – natural gas (mcf)	12,940	11,810	10
Total Canada (boe)	3,075	2,420	27
Colombia – oil (bbls)	2,194	1,031	113
Total Company (boe)	5,269	3,451	53

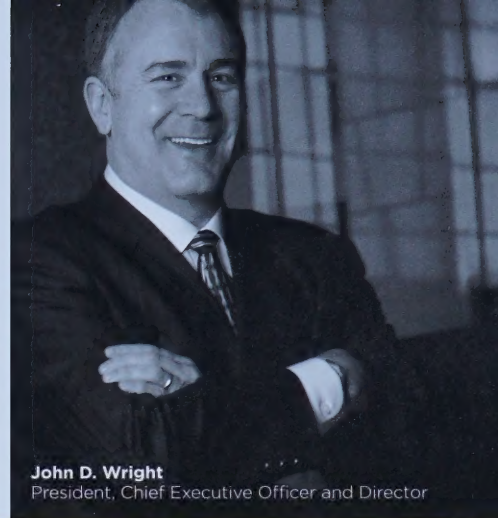
(1) Calculated based on cash flow from operations before changes in other non-cash working capital and asset retirement obligations settled.

(2) Includes working capital (deficiency), bank debt and subordinated notes.

(3) Six mcf of natural gas is equivalent to one barrel of oil equivalent ("boe"). Bitumen volumes are excluded from average daily production as WHITESANDS operations are considered to be in the development stage and accordingly are capitalized.

(4) Canadian sales prices are shown after transportation and forward gas sales contracts.

A LETTER FROM THE PRESIDENT



John D. Wright
President, Chief Executive Officer and Director

STRENGTH IN OUR VISION

The strength of our business units is what powers the performance of Petrobank. In conventional industry circumstances, based solely on their assets, operational performance and growth potential, each of these operations would be a strong, separate, independent company. Each of our business units has the power to identify unique new opportunities, develop specific business strategies and maximize the value we deliver to shareholders. Our Canadian Business Unit, Heavy Oil Business Unit and the Latin America Business Unit are independently managed to pursue their own strategic growth plans. Individually, these units are tracking strong growth trajectories, and collectively they have fueled our growth as a Company. Our vision for a strong Petrobank continues to unfold.

HEAVY OIL BUSINESS UNIT

World-class innovation and huge asset value best define this business unit. The WHITESANDS project in the Canadian oil sands has field-proven Petrobank's patented THAI™ process for the in-situ recovery and potential partial upgrading of heavy oil. From initiating construction in May 2005, to commencing production via the THAI™ process in July 2006, this project was completed in record time for any comparable oil sands project. The results continue to meet or exceed our expectations.

- We now have our first two THAI™ well pairs on-stream with a third pair about to commence production as we go to print.
- Production from the WHITESANDS horizontal wells has already exceeded our expectations, with stabilized well rates now targeting 1,000 to 2,000 barrels of fluid per day with ultimate oil cuts of 60 to 70 percent.
- With new oil sands leases acquired in 2006, the unit has a total of 39,680 acres and the identified gross bitumen-in-place is now 2.6 billion barrels.
- Our most recent reserve report identified 599 million barrels of 2P and best estimate contingent resource on the WHITESANDS lease. The report is based on Steam Assisted Gravity Drainage (SAGD) technology and does not give credit to the higher recovery potential of the THAI™ technology.

The success of the WHITESANDS project to date cannot be overstated. While we are working to continually improve on the process and learn from our mistakes, we are confident that the success of the THAI™ technology will have a profound impact on global heavy oil production. We recognize that the current WHITESANDS facility has proven inadequate for handling higher than anticipated well flow rates and has also been unable to cope with the amount of sand being concurrently produced at the site. This has led to a very low on-stream factor for the facility and inconsistent production rates to date. We therefore have plans in place for 2007 to de-bottleneck the facility to allow us to more efficiently handle increased production volumes. In addition, we will drill up to three new horizontal well pairs to test our Capri™ process, and the facility will be expanded to handle these volumes as well. Finally, this year at WHITESANDS, we plan to design the first 10,000 bopd modular expansion to the project.

The THAI™ process has proven to be extremely robust, dealing with a wide range of operating conditions in less than ideal reservoir parameters. With the potential to revolutionize heavy oil production worldwide, and with significant environmental benefits, the THAI™ process is now being moved into the international arena as we pursue opportunities to joint venture and license the technologies.





Finally, the technology arm of this business unit, Archon Technologies Ltd., is being expanded to increase its work in patenting improvements to the THAI™ process, and to continue to identify other leading technologies to complement our patent portfolio.

CANADIAN BUSINESS UNIT

The Canadian Business Unit is comprised of legacy assets with a deep inventory of development drilling locations, underpinned by an undeveloped land portfolio that has few peers in our industry. 2006 was a year of production growth and advancing a strategy to build our production base, expand on our existing plays and capture opportunities with long-term growth momentum. In this unit:

- Conventional production in 2006 increased 27 percent from 2,420 boepd to 3,075 boepd;
- We drilled 95 wells with a success rate of 91 percent;
- 3P (proved, probable and possible) reserves totaled 12.7 million barrels;
- Production grew to 4,192 boepd in the first two months of 2007; and,
- New ventures were identified with both near and long-term growth horizons.

The Canadian Business Unit has moved quickly to establish a competitive position in the emerging Bakken resources play in southeast Saskatchewan which, based on the Bakken experience in the US, yields large, long-life reserve potential and prolific initial production rates. Most of the increase in our production realized in the first part of 2007 is from Bakken wells drilled late in 2006.

Exploration has also been pushed to the forefront with large land holdings acquired in northwest Alberta that are on trend with one of the most exciting exploration plays in recent years.

In 2006, we experienced a drop in our total reserve base in Canada, partially due to reduced forecast prices for natural gas but also due, in part, to internal decisions to reduce or defer our capital and maintenance investments in the Jumpbush area until gas prices recover and development investments could be efficiently executed. We plan to focus on generating upward revisions to these reserve numbers in 2007 as we undertake a program of field and well maintenance to restore the Jumpbush production to its maximum potential. Our primary focus in 2007 will be the continued development of our Bakken light oil potential. We plan to drill a minimum of 40 horizontal wells in this play this year, a small fraction of the 200 locations we have identified to date.

LATIN AMERICAN BUSINESS UNIT

As our asset base has grown and evolved, so has the independence and diversity of each of our individual business units. Acknowledging this trend, in June last year we completed the initial public offering (IPO) of Petrominerales, our Latin American Business Unit, on the Toronto Stock Exchange. While Petrobank remains the majority shareholder with 80.7 percent of the outstanding shares, Petrominerales had obviously reached the point where it was performing as a pure Latin American player and needed to be treated in the same vein, sourcing proprietary capital and charting an independent course. Our long-term plan remains to ultimately see 100 percent of the shares of Petrominerales transferred to existing Petrobank shareholders and new Petrominerales shareholders.



2006 was a year of asset growth for Petrominerales.

- Production more than doubled to 2,194 bopd.
- We executed, or are in the final stages of negotiating, 13 exploration blocks covering 1.5 million acres of operated, 100 percent working interest lands in two highly prospective basins.
- 3P reserves totaled 33.9 million barrels at year end, a year over year increase of 52 percent.
- An exciting five-well exploration program commenced which will be targeting high impact wells in two of Colombia's most prolific basins.
- Our first exploration success, Ojo de Tigre 2, was cased as a potential oil well and is undergoing testing operations as this report goes to print.

Our three-prong approach to Colombia integrates immediate growth through development drilling at Orito and Neiva; medium term, high impact exploration in the Llanos and Putumayo Basins; and long term heavy oil development employing the THAI™ technology which is now fully formed and operational. Our development drilling programs have added significant reserves and our exploration inventory is starting to show some exciting promise at a very early stage. We have also successfully tied-up a massive acreage position in the Colombian heavy oil belt which shows great promise for potential resource accumulations suitable for projects involving THAI™. Our biggest challenge in Colombia is dealing with a burgeoning oil industry creating a shortage of services, equipment and people. The important thing is that we have put the reserves on our books and our concerted effort in 2007 will be to convert those reserves to profitable and growing production volumes.

GROWTH TARGETS

The independence of our business units and their strong performance allows us to push forward with aggressive growth plans. Over the next 18 to 24 months, each business unit has formulated an independent strategy to reach productive capability of 10,000 bopd. This benchmark, while challenging, will see three powerful independent growth engines individually and collectively build value for the shareholders of Petrobank.

WORKING IN COMMUNITIES

Despite the diversity of our business units, we have continued to employ strong, consistent values in the communities where we do business. Petrobank's team represents a broad spectrum of cultures, nationalities and languages. While respecting the unique cultures and environments in which we do business, we are able to bring Petrobank values into our community relations. This is displayed throughout the Company by the fact that the majority of our employees in Calgary and Bogotá are either bilingual or multi-lingual and comfortable in a broad cross-section of global cultures.

While our fundamental corporate value is delivering value to our investors, we do not allow this to cloud our way of integrating respect for local communities and the environment into our operations. This entails a commitment far beyond community donations; it extends into the full arena of shared social responsibility. We invest time and sweat equity to develop a



TH THAI'S™ REDUCED SURFACE
FOOTPRINT, SMALLER SCALE
FACILITIES, ELIMINATION OF LONG-
TERM WATER CONSUMPTION AND
PERCENT LOWER GREENHOUSE
GAS EMISSIONS, FUTURE PROJECTS
CAN POSITIVELY ADDRESS COMMUNITY
CONCERNS AND CREATE A "BEST
NEIGHBOUR" SOLUTION.

meaningful dialogue and community presence across our operations. We believe, ultimately, this deep-seated approach to our business yields value to our shareholders and to the communities where we actively participate.

In the Canadian Business Unit, our community-based approach can be seen through our interactions with our First Nation partner at Jumpbush and the greater community in the Princeton area. In our Latin American Business Unit, we have been cited as setting an industry-wide "best practice" through our ability to integrate local communities into all aspects of our operations. The same approach is found in our Heavy Oil Business Unit; not just in our community consultation process, but in planning for the commercial development of THAI™, which could see our process creating a source of agricultural quality water and low cost electricity as spin off benefits to development of heavy oil fields around the world.

Our approach requires more time and effort from our people but the results are worth it; especially when long-term relationships provide positive outcomes for the community, for each business unit individually, and for Petrobank as a whole.

THE INDUSTRY ENVIRONMENT

The world energy industry is increasingly more complex and continues to evolve. In Canada, for example, the federal government's recent proposed legislation regarding the taxation of trusts will bring change to the Canadian industry. We had never planned to become a trust and we continue to own and manage our assets for the long haul. However, one of the outcomes of these new tax proposals is likely to be rationalization within the trust sector and the oil industry as a whole, and we are fortunate to have a team of highly skilled people experienced with acquisitions and divestiture. Our track record speaks strongly of success based on a number of transactions we have successfully completed, and the quality of assets in both our Canadian and Heavy Oil Business Units.

In Colombia, the reforms to the hydrocarbon sector initiated in 2004 have created a major boom throughout the country's oil industry. While we are sometimes challenged to source equipment, services and personnel in this rapidly strengthening economy, we are fortunate to possess a huge undeveloped land base in two highly prospective areas. In the Canadian heavy oil industry, we are experiencing a near "perfect storm" of soaring capital and operating costs, equipment and labour shortages, project delays and serious environmental concerns. In the eye of this hurricane we find WHITESANDS and the THAI™ / Capri™ technology advantage offering substantial, bedrock solutions to all of these problems. Finally in the conventional Canadian oil industry, where players are chasing diminishing returns and smaller and smaller prizes in a mature basin, we are blessed with solid multi-year growth opportunities in both light oil and natural gas, and some exciting exploration upside.

PETROBANK'S EVOLUTION

Petrobank is somewhat unique in our industry with the variety, strength and diversity of our business units. Looking down the road, as each unit continues to build financial strength and stronger operational foundations, Petrobank has the ability to continue to evolve into multiple, separate companies, as we continue to revolutionize our business and the uniqueness of our operations. Regardless of corporate structure, we will continue to maintain a firm eye on creating value for shareholders.

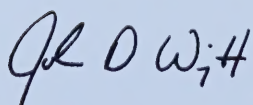
No matter how we evolve, we believe that Petrobank and our component parts will remain an attractive investment. Our earnest approach to business and innovation and the collective skill-set of our employees will hopefully continue to set us apart and allow us to be a valuable part of any investment portfolio.

IN CLOSING

While it is always tempting to paint a pretty picture of the Company's capabilities and potential, it is important to remember that we face huge challenges in our operations, every day of the year. To overcome these challenges requires hard work and dedication. The expectations we place on ourselves to meet the goals we share with our shareholders can create frustration, especially when we repeatedly experience difficulty achieving desired outcomes. Add to this the complexities of managing regulatory delays, difficulties getting our wells tied-in or on-stream as quickly as we want, the availability of labour to construct facilities and ultimately keeping everything running efficiently, and it is evident why we rely on the strength of our people. A key attribute of Petrobank, in which I have total confidence and faith, is the ability of every one of our employees to pitch in, learn from our mistakes and find innovative solutions to whatever new challenge confronts us. I encourage you to assess our vision and value statement with the comfort of knowing that these are not just empty words but our chosen way of doing business.

The Board, employees, and management of Petrobank have all bought into our strategy to grow each of our business units to 10,000 boepd and beyond in the next 18 to 24 months. These are not trivial goals and they will require focused dedication on all fronts. We will face challenges and disappointments along the way, but I firmly believe that we have the ability to continue to transform and evolve the Company into a bigger and better enterprise, or collection of enterprises. My confidence and faith in this outstanding collection of professionals grows stronger every day. Their personal commitments to our Vision and Values help to drive the Company forward on the correct path. I've mentioned before the high degree of competency and innovation that everyone contributes to our growth, but I think I am most grateful to every employee and each of our Board members for their role in making Petrobank a great organization to belong to, everyday. Finally, I would like to thank all of our shareholders for their continuing faith and patience as we continue to advance Petrobank's game plan.

Respectfully submitted on behalf of the Board,



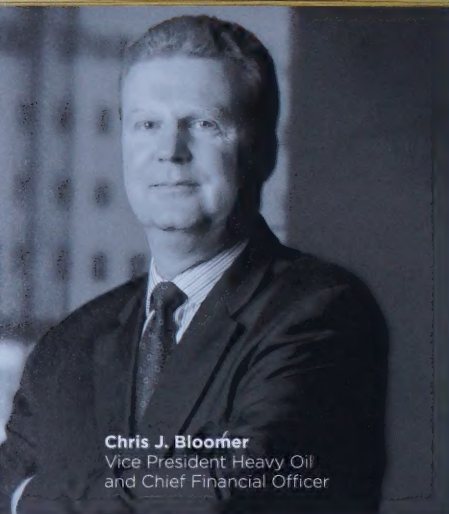
John D. Wright

March 19, 2007

PETROBANK VISION AND VALUES

- We focus on innovatively creating long-term shareholder value.
- We recognize that our key assets are our employees and we will treat them, and their families, with respect, providing opportunities for professional and personal growth, and reward them consistent with their efforts and performance.
- We encourage everyone involved in the operations of the Company to act as shareholders, and always in the best interests of shareholders.
- We act with honesty and integrity, conducting ourselves in an ethically and morally correct fashion in all of our business dealings.
- We recognize that our industry has an impact on the environment and we endeavour to follow best practices to minimize our environmental footprint within the realities of our operations.
- All our communication is conducted openly, honestly and with respect for individuals, communities and cultures.
- We are committed to safety.
- We encourage innovative thinking and treat mistakes as opportunities to learn and improve our future performance.

STRENGTH IN HEAVY OIL



Chris J. Bloomer
Vice President Heavy Oil
and Chief Financial Officer

THE THAI™ PROCESS IS BEING FIELD TESTED AT THE WHITESANDS PROJECT WITH ONGOING RESULTS MEETING OR EXCEEDING INITIAL EXPECTATIONS.

THAI™ HAS ADVANCED FROM THE DEMONSTRATION OF A PROMISING TECHNOLOGY TO A SUSTAINABLE COMMERCIAL PROCESS TO UNLOCK THE CANADIAN OIL SANDS AND HEAVY OIL GLOBALLY.

WE PLAN TO CAPTURE A GLOBAL PORTFOLIO OF HEAVY OIL ASSETS FOR THE APPLICATION OF THAI™.

Our unique Heavy Oil Business Unit continues to develop what may be the most exciting opportunity in the oil industry today.

PETROBANK'S THAI™ PROCESS

Petrobank's patented THAI™ process is a step-change in the recovery of heavy oil and bitumen resources worldwide. While there are other technologies in use, the THAI™ process has many advantages ranging from speed of project execution, lower capital and operating costs, lower environmental impact, and higher resource recovery potential. THAI™ is the most sustainable of currently available technologies.

In just over a year, Petrobank constructed a demonstration project and commenced production using the THAI™ process. The WHITESANDS project, operated by Petrobank through its 84 percent owned subsidiary, WHITESANDS Insitu Ltd., is sited on a portion of our 62 sections of oil sands leases in the heart of Alberta's in-situ oil sands fairway. With the successful start-up of the WHITESANDS project, the benchmarks established for proving the THAI™ technology have all been met or exceeded and, while the demonstration project is continuing, Petrobank is moving forward with expansion plans and further commercial applications.

DEVELOPMENT BENCHMARKS ACHIEVED:

- ✓ Designed and built pilot project
- ✓ Initiated Pre-Ignition Heating Cycle (PIHC) phase on all three wells
- ✓ Established conditions to initiate air injection
- ✓ Confirmed horizontal well production capability
- ✓ Initiated air injection
- ✓ Confirmed continuous high temperature combustion
- ✓ Established oil production under combustion
- ✓ Started up second well pair on combustion
- ✓ Confirmed high carbon dioxide to carbon monoxide ratio
- ✓ Produced gas content indicative of in-situ thermoc cracking
- ✓ Free hydrogen indicates high temperature combustion reactions
- ✓ No air breakthrough
- ✓ High productivity from horizontal wells and increasing oil cut

CHALLENGES OF THE CANADIAN OIL SANDS

The bitumen contained in the Canadian oil sands is immobile and, prior to THAI™, could only be produced through open-pit mining where it is encountered close to the surface or, where the bitumen is too deep to mine, through the addition of steam heat into the reservoir. To date, in-situ recovery using Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) has been utilized to inject steam to heat the reservoir and mobilize the bitumen so that it can flow to a production well. These steam-based processes can recover 20 to 50 percent of the bitumen-in-place.

SAGD involves drilling one horizontal well near the bottom of the reservoir and a second horizontal steam injection well 3-5 metres above the production well. The steam rises, mobilizing the bitumen which drains into the lower horizontal well and is pumped to surface. CSS uses one vertical well to inject steam for a period of time, after which the heated bitumen and condensed water is pumped to surface using the same well. In CSS the steam is injected at a high pressure, often high enough to fracture the reservoir rock, and the steam injection and oil production is repeated over many cycles.

Steam processes are not sustainable technologies as they are energy intensive, consuming approximately one mcf of natural gas per barrel of bitumen produced. The environmental impact is also high with large amounts of water required to generate the steam and the associated emission of significant volumes of greenhouse gases from the burning of natural gas and other hydrocarbon fuels.

THAI™ SOLUTIONS

Petrobank believes that the THAI™ process is a more sustainable technology and will demonstrate numerous advantages over SAGD, including:

- **lower capital costs and production costs**
- **higher expected resource recovery**
- **minimal use of natural gas and fresh water**
- **a partially upgraded crude oil product**
- **reduced diluent requirements for transportation**
- **significantly lower greenhouse gas emissions**
- **shorter capital investment cycle and faster time to production**
- **less susceptibility to cost overruns**

"THAI™ – the solution to the in-situ oil sands challenges"

COMMERCIALIZATION

In addition to developing a major oil sands production platform at WHITESANDS, Petrobank's strategy is to capture a global portfolio of heavy oil resources where the application of the THAI™ technology could lead to greatly improved recovery rates and significant long-term value for the Company. Deployment of THAI™ globally presents opportunities to acquire and develop resources, as well as license the technology to third parties.

Based on the field-demonstrated performance in the Canadian oil sands, Petrobank is moving forward with expansion into the international arena, particularly in Latin America. To date, technology-sharing agreements have been signed with Petrobras, Ecopetrol, PetroEcuador, PDVSA and Petro China. These agreements permit sharing of information on reservoirs where THAI™ could be applied, and the potential for the application of the technology leading to a development project.

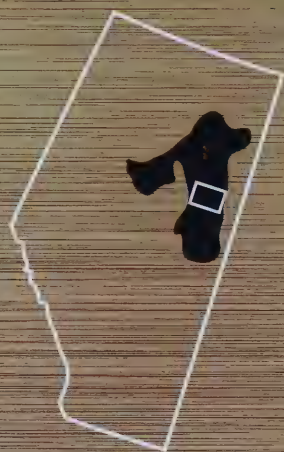
Colombia is at the forefront of this activity where, in addition to working with Ecopetrol, Petrobank, through its 80.7 percent interest in Petrominerales, has exposure to three exploration blocks covering 818,173 acres in the Llanos Basin heavy oil belt. Petrominerales already has a license agreement with Petrobank's subsidiary, Archon International Technologies Inc., for the application of THAI™ in Colombia.

In addition to direct resource capture opportunities, Archon has been commissioned to evaluate target reservoirs in Texas and Africa on behalf of other independent third parties with a view to the potential application of THAI™.

The performance of THAI™ at the WHITESANDS project has given us confidence that the technology will soon be available for heavy oil activities around the world. The cost effective nature of the process, when added to the environmental strength THAI™ offers, makes it an ideal technical solution.

INDUSTRY PARTICIPANTS IN THE OIL SANDS, INCLUDING PETROBANK, ARE CONTINUOUSLY STRIVING TO MINIMIZE THE ENVIRONMENTAL FOOTPRINT, REDUCE EMISSIONS, IMPROVE RECOVERIES AND MAKE OPERATIONAL EFFICIENCIES. THAI™ GIVES PETROBANK THE OPPORTUNITY TO CREATE A STEP-CHANGE IN THE SUSTAINABILITY OF OIL SANDS DEVELOPMENT.

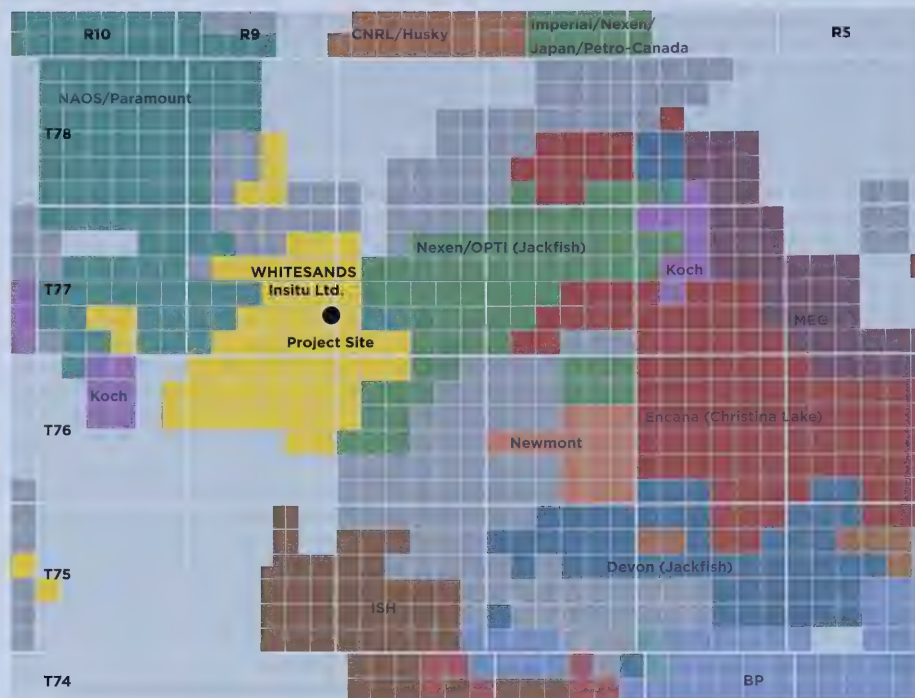




CANADA'S OIL SANDS

- 1.7 TRILLION BARREL RESOURCE
- 170 BILLION BARRELS RECOVERABLE WITH CURRENT TECHNOLOGIES (MINING, CSS AND SAGD)
- CURRENTLY PRODUCING 1.1 MILLION BARRELS PER DAY
- CURRENTLY 10 PERCENT OF NORTH AMERICA'S OIL PRODUCTION COMES FROM THE OIL SANDS
- FORECAST PRODUCTION OVER 3 MILLION BARRELS PER DAY BY 2015
- \$100 BILLION OF PLANNED INVESTMENTS

THAI™ COULD POTENTIALLY RECOVER 70-80 PERCENT OF THE BITUMEN-IN-PLACE IN THE OIL SANDS VERSUS 20-50 PERCENT FROM CURRENT IN-SITU TECHNOLOGIES.



WHITESANDS owns 62 sections of oil sands leases

WHITESANDS RESERVES/RESOURCES AND NET PRESENT VALUES

	Gross Reserves/Resources			NPV 8% - Before Tax		
	Dec. 31, 2006 (mbbl)	March 1, 2007 (mbbl)	Increase (mbbl)	Dec. 31, 2006 (\$ millions)	March 1, 2007 (\$ millions)	Increase (\$ millions)
Probable Reserves (2P)	25,290	25,290	-	(24.7)	(24.7)	-
Probable plus Possible Reserves (3P)	70,323	70,323	-	163.1	176.1	12.8
Low Estimate Contingent Resources	335,689	405,263	69,574	120.0	225.6	105.6
Best Estimate Contingent Resources	468,009	574,060	106,051	605.2	831.9	226.7
High Estimate Contingent Resources	590,064	728,491	138,427	1,047.3	1,384.5	337.2
2P + Low Estimate Contingent Resource	360,979	430,553	69,574	95.3	200.9	105.6
2P + Best Estimate Contingent Resources	493,299	599,350	106,051	580.5	807.2	226.7
2P + High Estimate Contingent Resources	615,354	753,781	138,427	1,022.6	1,359.8	337.2

To date, our reserve and resource estimates are still based on SAGD technology as it is the presently recognized technology used to define in-situ oil sands reserves. This does not in any way reflect the technical merits of the THAI™ process. It is simply the industry standard to recognize a portion of our reserve and resource potential on the WHITESANDS leases. Once our independent engineers can certify reserves associated with the THAI™ process, this SAGD-based analysis will be phased out.

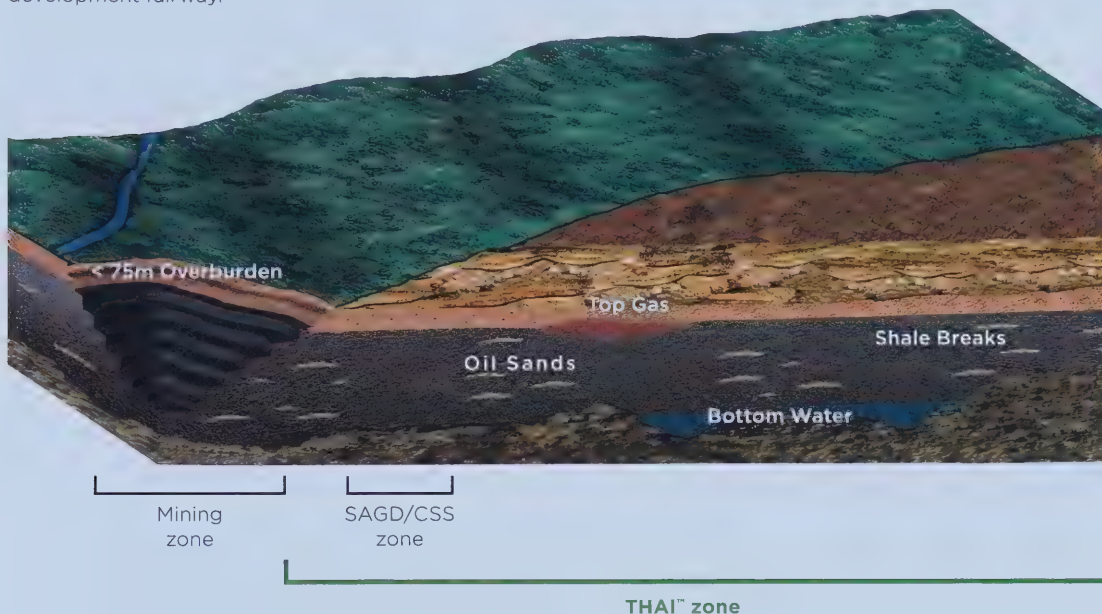
Petrobank has a world-class heavy oil resource on our 62 sections of oil sands leases. Delineation drilling continues to add significant new recoverable bitumen resources. In 2006, five wells were completed and in the first quarter of 2007 an additional eight wells were completed to further delineate our land base and expand the estimated recoverable resource.

These delineation wells extended our significant McMurray channel and, when incorporated into the independent reserve evaluation effective March 1, 2007, resulted in a 48 percent or 210 million barrel increase in the best estimate of recoverable gross working interest bitumen resources on the lands when compared to our initial May 1, 2006 evaluation.

The THAI™ Application - Increasing the Potential of the Canadian Oil Sands

THE CANADIAN OIL SANDS

The Canadian oil sands is the world's largest accumulation of hydrocarbon. Located in northeastern Alberta, the oil sands underlie approximately 140,000 square miles, an area the size of Florida, and contain bitumen, a thick tar-like hydrocarbon which requires significant upgrading. Petrobank's WHITESANDS assets are situated in the heart of the in-situ oil sands development fairway.



THAI™ has the potential to operate in lower pressure, lower quality and deeper reservoirs than current steam-based processes.

Mining

When oil sands have less than 75 metres of overburden, mining is used to extract the bitumen. Mining requires massive trucking operations to haul the oil sands for processing.

Steam-based technologies

Several technologies rely on steam to heat and soften the bitumen underground allowing it to flow to production wells. Both CSS and SAGD are considered economic only in very high-grade, relatively homogeneous oil sands reservoirs, which is only about 10 percent of the resource base, and can only recover 20-50 percent of the bitumen-in-place.

THAI™ has the potential to recover 70-80 percent of bitumen-in-place versus 20-50 percent from current in-situ technologies.

THAI™ could also be applied to previously steamed reservoirs to recover bitumen left behind by CSS and SAGD.

THAI™ has the potential to operate in reservoirs where other steam-based recovery methods can not.

Unlike current steam-based technologies, THAI™ is not as impacted by the geologic variables found in the oil sands.

Thinner reservoirs (less than 10 metres) can be a target for THAI™ as only one horizontal well is required compared to two horizontal wells with SAGD. THAI™ is not as sensitive to the presence of top or bottom water, which act as heat thief zones, nor the absence of top gas that provides some reservoir pressure.

One of the main geological variables of the oil sands is large shale lenses which act as barriers for steam migration. These shale lenses are less of a concern with THAI™ as the process creates its own pressure regime and operates at very high temperatures, allowing heat to penetrate around these potential barriers.

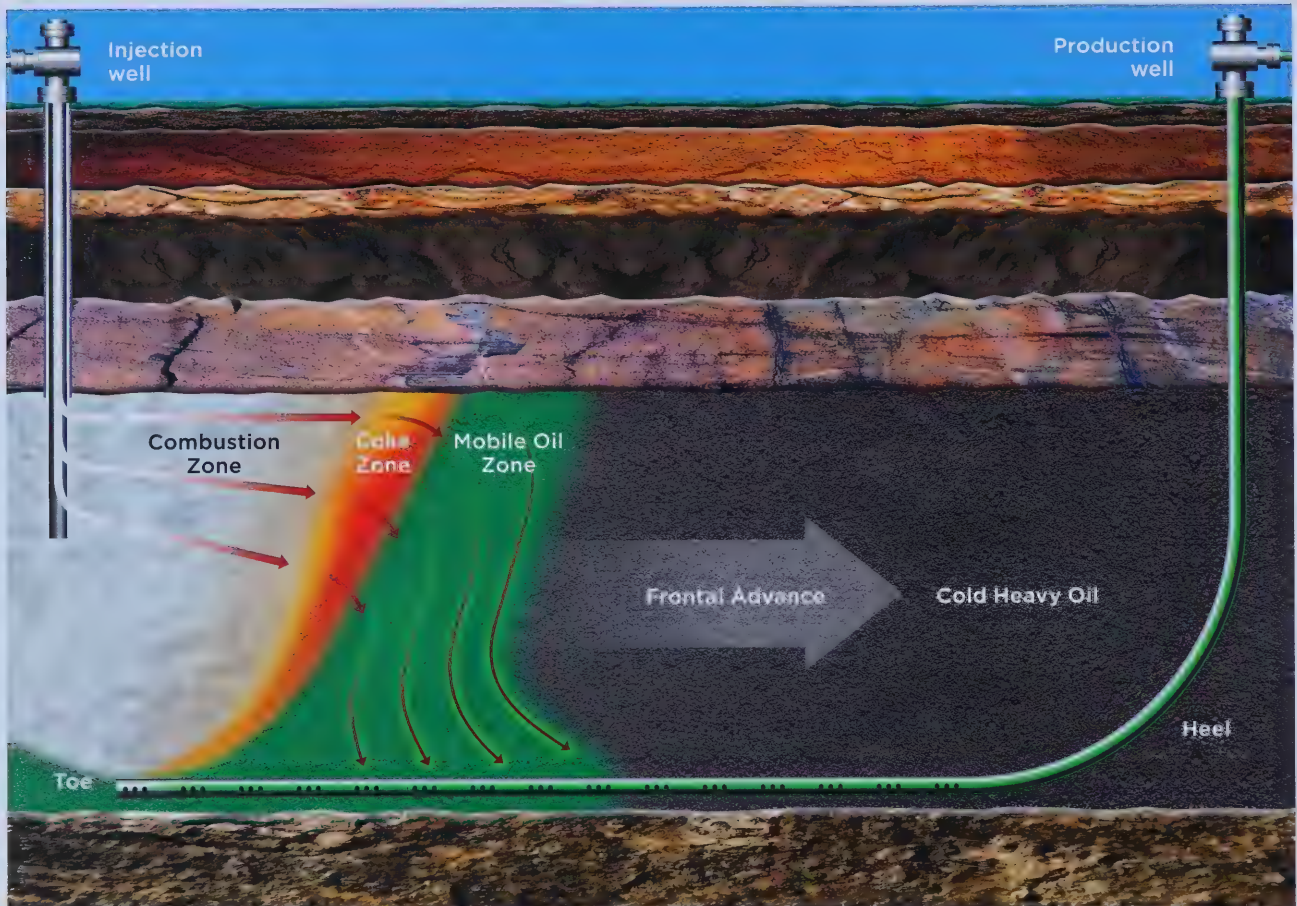
The THAI™ Process

THAI™ is an evolutionary new configuration for in-situ combustion which combines a horizontal production well with a vertical air injection well placed at the toe.

During the process a high temperature combustion front is created.

Part of the oil in the reservoir is burned, generating heat which reduces the viscosity of the remaining oil allowing it to flow by gravity to the horizontal production well.

The combustion front sweeps the oil from the toe to the heel of the horizontal producing well, recovering up to an estimated 70-80 percent of the original oil-in-place while partially upgrading the crude oil in-situ.



Why THAI™? The potential benefit is sweeping

Higher resource recovery

- Estimated 70-80 percent recovery of oil-in-place
- Potentially feasible over a broader range of reservoirs including: low pressure, thinner, previously steamed, deeper, removal of gas over bitumen; or top and bottom water

Improved economics

- Lower capital cost – only one horizontal well, minimal steam and water processing facilities
- Lower operating cost – negligible natural gas, minimal steam generation and minimal water processing
- Potential for higher netbacks for partially upgraded product and less diluent use
- Faster project execution time

Lower environmental impact

- Negligible fresh water use
- 50 percent less greenhouse gas emissions
- Smaller surface footprint and easier reclamation

Field Scale Simulation

These diagrams are taken from the Computer Modelling Group's "STARS" field-scale numerical simulation model, which is used to evaluate the process under field scale conditions.

Pre-Ignition Heating Cycle (PIHC)

At start-up the horizontal and vertical wells are steamed for a short period of time to warm the horizontal well and to create mobility around the vertical well to facilitate air injection. Work is being done to replace steam with a more energy efficient heat source.

Combustion initiation

Air is injected into the reservoir, auto-igniting the oil creating a high temperature combustion zone (400 to over 700°C). The hot combusted air contacts the cold oil in front of the combustion zone causing the lighter oil fraction to be mobilized and the heavier fraction to be coked onto the reservoir sand. The coke is the fuel for the ongoing combustion reaction. The light oil and vaporized reservoir water are swept into the horizontal well and to surface. The combustion front is estimated to move at the rate of 23 cm a day or 100 metres per year.

Steady state

As air injection continues, the oil drainage front broadens until it reaches the edge of the modeled zone. At this time, a continuous air bank is established and production is estimated by reservoir models to be constant at 630 bopd. At steady state, the shape of the oil drainage front is constant, enabling control of the oxygen flux and assuring that the high-temperature oxidation process predominates.

End state

Once the front edge of the drainage volume reaches the heel of the horizontal producer, the next set of follow-on horizontal wells can be drilled. The reservoir is already preheated and the process can continue on in the steady state phase at peak production rates without additional start-up phases.

The region behind the burning front is swept of oil, demonstrating why high recovery factors are expected with the THAI™ process.

The reservoir

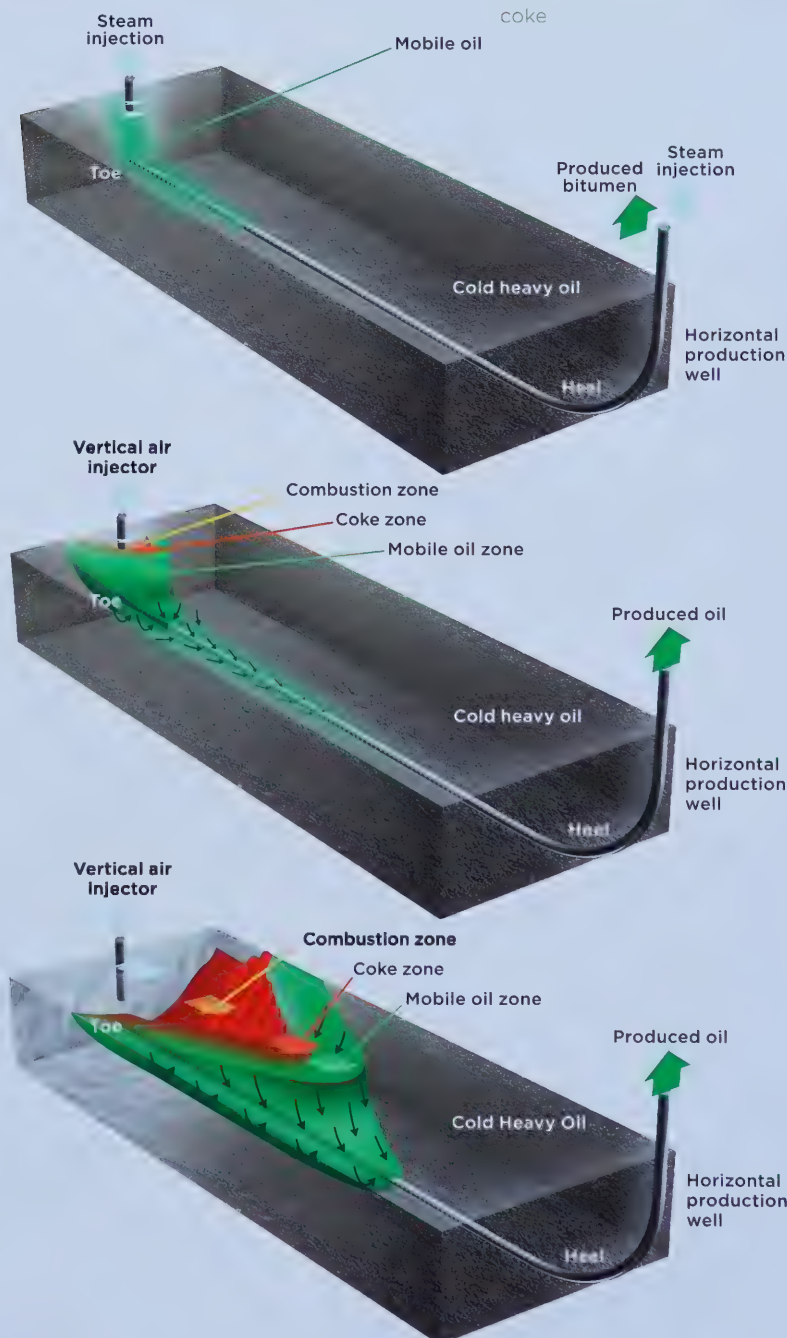
The box represents the volume of the bitumen reservoir that will be swept by the THAI™ process. It has dimensions 500m x 100m x 20m with 80 percent original oil saturation and is representative of one WHITESANDS well pair.

Coke zone

The red area shows where the heavy fractions (coke) are being deposited in the reservoir. Coke is the fuel for the process.

Mobilized oil

The green area is where oil saturation has been reduced to 50 percent from 80 percent showing that oil has moved from the zone into the horizontal well. Ultimately, most of the remaining oil will be swept from this area, leaving only coke





PROVING THE THAI™ PROCESS

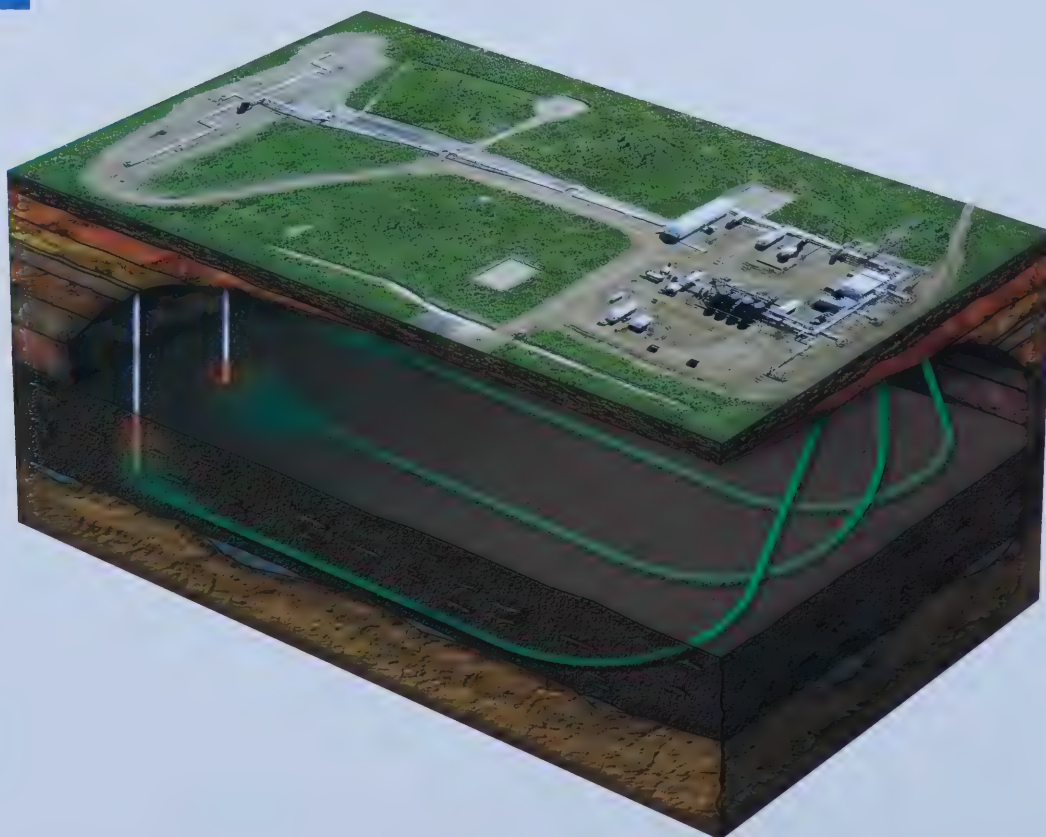
Start-up of the WHITESANDS project began in late March of 2006 with the initiation of the PIHC (Pre-Ignition Heating Cycle) in the central well pair. Air injection and combustion were initiated in mid-July 2006 and by year end, production had ramped up considerably, with gross production capability from the first horizontal well of up to 2,000 barrels of fluid per day, approximately double our initial forecast rate, with oil cuts currently between 40 and 50 percent.

Achieving these early results in the oil sands has been accomplished in record time compared with other in-situ projects such as SAGD. Indications are that with wells on full production, daily rates significantly in excess of 1,000 barrels of fluid could be achieved with 60 to 70 percent oil cuts, considerably higher than originally anticipated.

During the year, numerous benchmarks were achieved that have field proven the process. In addition to achieving major milestones, the higher than planned flowing capacity of the wells, and the higher sand production in the first production well, have meant we have been operating with low on-stream factors and at highly restricted choke rates.

Modifications to the surface facilities, including enhanced sand handling capability, as well as wellhead and choke enhancements, have improved the operating efficiencies. Additional debottlenecking is underway to improve the efficiency and capacity of current operations and to accommodate a plant expansion for up to three additional wells.

One of the expected benefits of THAI™ is partial upgrading in-situ. While we did not expect to see a consistently upgraded produced oil this early in the process, we now believe that we are beginning to see some partially upgraded bitumen. One of the unique aspects of the oil produced by the THAI™ process is the lack of difficult emulsions and a clean oil/water separation. Recent production from the first well pair has demonstrated further improvements in oil/water separation and a reduced viscosity compared to our earlier production, leading us to believe that we are beginning to see an upgrading effect.



PROJECT DEVELOPMENT TIMELINE

Regulatory application submitted - November 2003

Regulatory approval received - February 2004

Project financing - April 2005

Project construction commenced - May 2005

2006

Pre-ignition heating cycle (PIHC)

In March steam injection was initiated into the central vertical injection well of the three well pairs. This initiated the PIHC necessary to soften and mobilize the bitumen prior to air injection.

Air injection and combustion confirmed

Air injection was initiated on the first well pair in July, with air continually being injected into the vertical well. During the first three weeks, in-situ combustion was confirmed based on various indicators, including significantly rising temperatures in the reservoir zone, production of combustion gases and rising temperatures in the horizontal well bore temperatures. Several months later, reservoir temperatures of over 1,000 degrees C were recorded. The data suggest that oil is being partially upgraded in-situ.

Production grows by year end

The combustion front is still in the early stages, affecting only two to three percent of the total reservoir volume anticipated to be impacted by the fireflood over the life of each THAI™ well pair. The gross production capability from the first horizontal well has demonstrated a capability of up to 2,000 barrels of fluid per day, approximately double the initial forecast rate. Oil cuts have increased to a 40 to 50 percent range.

Surface facilities

Facility modifications have been made to the sand handling equipment to allow for a better on-stream capability.

Combustion initiated on second well

In late October, the PIHC was initiated and in early January 2007, air injection commenced on the second well pair. Combustion was confirmed in less than one week with temperature readings in the horizontal and vertical wells exceeding 400 degrees C. While still early in the combustion phase, we have experienced a more rapid increase in fluid production and oil cut in this second well pair, compared to the same stage in the first well pair. This is attributed to the significant reduction in steaming in the PIHC phase. As the combustion front expands, production is expected to increase to a rate comparable with the first well pair.

2007 PLANS

Start-up of third well pair

The PIHC phase was initiated on the third well pair in December 2006, and as we go to print with this report, we are preparing to begin air injection and combustion.

Continued optimization

The WHITESANDS project is undergoing a continuous improvement process with ongoing modifications to certain aspects of the surface facilities and operating procedures.

Production growth anticipated

As the process advances and air injection rates are increased to design volumes, and with all three well pairs in operation, significantly higher bitumen production and overall resource recovery is expected, with the anticipation of some degree of in-situ upgrading.





Archon's THAI™ scaled laboratory reactor

Test Capri™ technology

Up to three more horizontal well pairs will be drilled in 2007 to test our patented Capri™ technology, a catalyst process with the potential to lower the temperature at which thermal cracking occurs, potentially generating additional upgrading in-situ.

Debottleneck and expand current facilities

Existing facilities will be expanded to handle higher than anticipated well productivity and to accommodate production from the Capri™ wells planned for 2007.

COMMERCIALIZATION

Initiate 10,000 bopd project

Based on results to date, design is being initiated on an additional 10,000 bopd WHITESANDS project. An application for regulatory approval is expected to be submitted prior to year end. The project is in addition to the 2007 Capri™ drilling program and facility expansion.

Our strategy is to modularize the process so that our project design can be consistently implemented over a broad range of applications globally.

Our philosophy is to *"Design one – build many"*.

Conventional heavy oil project

We are also focused on developing an additional THAI™ project in a conventional heavy oil reservoir in Canada and/or internationally.

ARCHON TECHNOLOGIES LTD.

Research and development activities are conducted under two subsidiaries, 100 percent owned by Petrobank, Archon Technologies Ltd. (Archon) and Archon Technologies International Inc. Proprietary laboratory facilities were established in 2005 and Archon is now playing an increasingly important role in the development of new technologies and enhancements to the THAI™ process, as well as the evaluation of complementary technologies. Ongoing activities include the advancement of CAPRI™, which adds a catalyst around the horizontal production well to increase the upgrading effect in-situ, concurrent with the THAI™ combustion process.

Archon also performs a vital function in the ongoing evaluation of the operation of the WHITESANDS project by analyzing produced gases, water and oil, as well as generating solutions to operating issues as they arise. This creates valuable operational know-how and intellectual capital in the technologies.

Two new patents have been developed by Archon, "Well Bore Control" and "In-Situ Diluent Enhancement". There are several further original processes being evaluated that should result in additional patents pertaining to the elimination of steam in start-up and partial surface upgrading.

In 2006, in conjunction with the Petrominerales IPO, Archon, through its offshore subsidiary Archon Technologies International Inc., entered into a licensing agreement with Petrominerales for use of the THAI™ technology in Colombia. Archon plans to enter into license agreements with other third parties on a similar basis to the Petrominerales license.

COMMUNITY RELATIONS

The Heavy Oil Business Unit, through the WHITESANDS project, is proactive in its communications with the local communities of Conklin, Chipewyan Prairie Dene First Nation, and Heart Lake First Nation. There is regular dialogue with the communities providing updates about project operations and opportunities for discussion of community issues where the Company might play a supporting role. As a matter of practice, local contractors with the appropriate services and skills are contracted to work on the project. Health, safety, environment and community relations are integral to the WHITESANDS operation.

Petrobank's Canadian Business Unit, operating in the hydrocarbon-rich Western Canadian Sedimentary Basin, is expanding rapidly through successful exploration and development.

CANADIAN BUSINESS UNIT

The Canadian Business Unit is focused on growth through the drill bit, combining low risk development opportunities with focused exploration in strategic areas, and capturing substantial growth in an exciting resource play which is just gaining momentum. Petrobank's strength in building this business unit has evolved from our strategy of acquiring under-developed oil and gas properties and exploiting those assets through internally generated exploration and development concepts.

The Canadian Business Unit has considerable operational flexibility through its extensive land holdings and a substantial inventory of oil and gas drilling opportunities. With such operational breadth, we have the ability to move capital between projects to balance the risk profile, and to adjust our exposure to commodity prices. The Canadian Business Unit is positioned for long-term light oil and natural gas production growth, complemented with high impact exploration potential.

Production growth

The Canadian Business Unit's two main producing properties are at Jumpbush and Red Willow, with the Bakken resource play in southeast Saskatchewan rapidly playing a larger role in the Company's production base. In 2006, 91 percent drilling success on 95 wells (79.6 net) increased production by 27 percent to 3,075 boepd from 2005, despite delays in bringing new production on-stream. Production during the first two months of 2007 has increased further to 4,192 boepd, largely as a result of new Red Willow gas and Bakken light oil production brought on late in 2006 and early 2007. Our 2007 capital program is largely focused on Bakken drilling and accordingly light oil production is expected to increase significantly throughout 2007.



R. Gregg Smith
Vice President, Canada





**THE CANADIAN BUSINESS UNIT
COMBINES A BALANCED INVENTORY
OF LOW-RISK DEVELOPMENT DRILLING
LOCATIONS INCLUDING BOTH SHALLOW
GAS AND LIGHT OIL WITH HIGH-IMPACT
EXPLORATION.**

Emerging resource play

Petrobank holds a strong competitive position in the Bakken play near the Saskatchewan/Manitoba border. The Bakken is a large regional resource play initially exploited in the United States, with development of this thick low-permeability horizon just gaining momentum in Canada. The Company's strengths are in its large acreage position and internally developed technical abilities in this play, which has significant upside for production and reserve growth over the next several years.

Undeveloped land base

One important strategic advantage for Petrobank is a large undeveloped land base of 304,000 net acres, a portfolio that is unique for a company our size. Over half (154,000 acres) of these lands are non-expiring, where the Company uniquely owns the underlying mineral rights. Petrobank continues to leverage the strength of this land base into new opportunities.

Exploration potential

With a strategy of adding value through the drill bit, Petrobank is aggressively moving forward on new, potentially high-impact exploration prospects in two key areas of northwestern Alberta. Petrobank will begin to test the multi-zone oil and gas potential of these areas with at least two exploration wells in 2007.

JUMPBUSH/MILO, ALBERTA

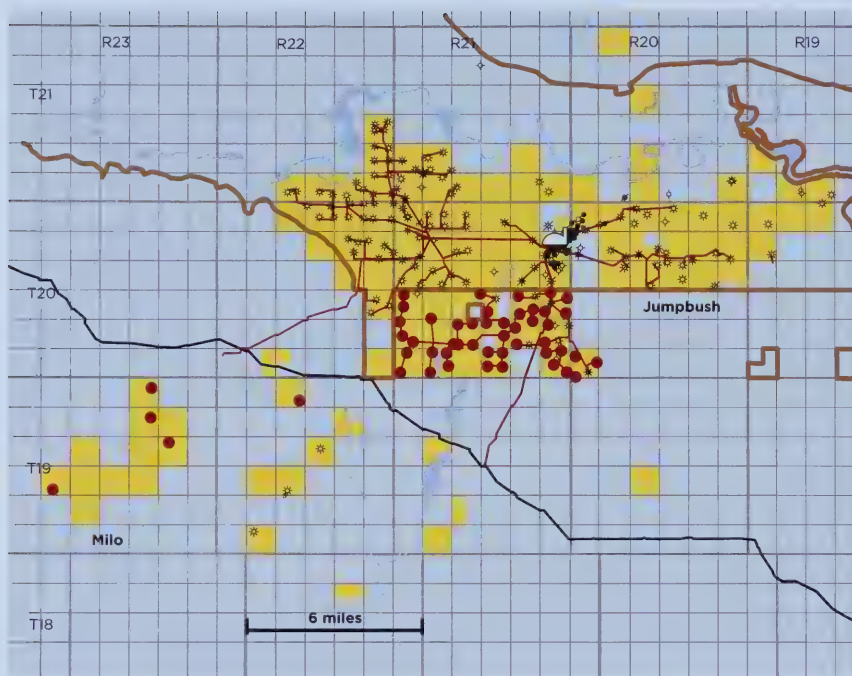
LAND BASE AT 12/31/06	65,961 acres (42,292 net)
WORKING INTEREST	70-100 percent operated
PRODUCING WELLS	150 gas wells (108.9 net); 14 oil wells (9.8 net)
PRODUCTION PERCENTAGE	49 percent of 2006 Canadian Business Unit production

- 100 percent drilling success on 169 wells since 2003
- Drilled 50 wells (42.3 net) in 2006
- 2006 production of 1,495 boepd, 98 percent natural gas (8.8 mmcf/d), which is consistent with 2005 levels. Most new production added either late in 2006 or early 2007
- 16 square kilometres of 3-D and 48 kilometres of 2-D seismic acquired
- 2007 plan to drill up to 50 wells
- Long-term CBM potential

Main gas producing property

Jumpbush is Petrobank's largest producing area by volume and a major focus of drilling for its shallow, long-life gas reserves. The Company has a large inventory of low risk, multi-zone prospects exceeding 175 locations, extensive infrastructure and operates a gas plant with capacity of 25 mmcf/d (17.5 mmcf/d net).

Jumpbush is a unique opportunity as it encompasses under-developed lands on the Siksika First Nation, approximately 100 kilometres east of Calgary, and an expanding acreage position outside of the Nation. Petrobank is operator and 70 percent working-interest partner with Siksika Energy Resources Corporation (SERC) on the First Nation lands.



- | | | | |
|---|--------------------|---|----------------------|
|  | Petrobank gas well |  | Petrobank pipelines |
|  | 2006 wells drilled |  | Industry pipelines |
|  | Petrobank land |  | Siksika Nation |
| | |  | Petrobank facilities |

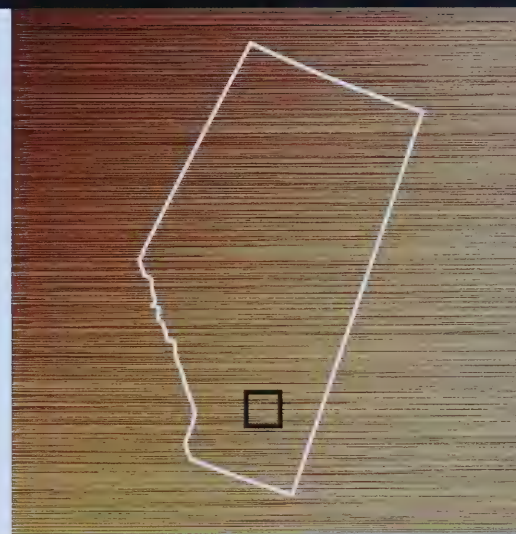
Significant gas potential

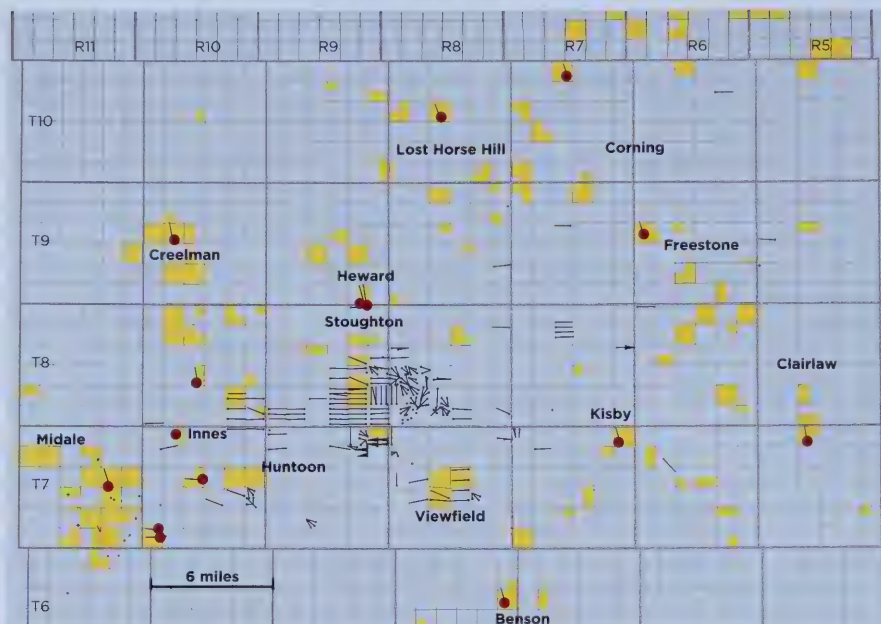
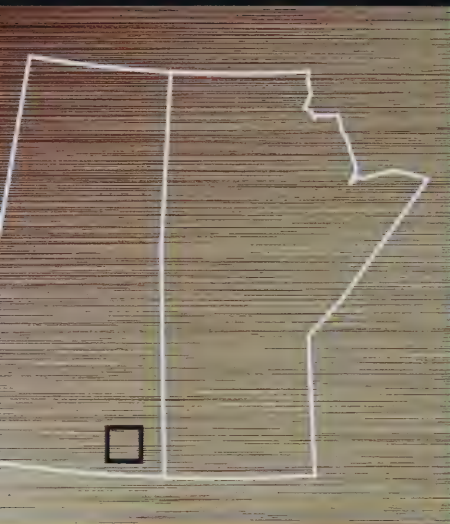
The Jumpbush program is primarily a conventional shallow gas play in the Belly River and Medicine Hat formations. The Belly River has several zones capable of natural gas production, with any individual well having a strong likelihood of encountering at least one gas-bearing zone. By contrast, the deeper Medicine Hat formation contains a single gas-saturated, low permeability sandstone of variable productive capability, which is encountered in almost every well drilled. Wells are typically drilled to a depth of 830 metres and to date, Petrobank has achieved a 100 percent drilling success rate.

In addition to natural gas, an extensive coal bed methane (CBM) resource is present in both the Belly River and Horseshoe Canyon coals. Other operators in the vicinity are beginning to develop these CBM resources. For Petrobank, this CBM resource represents a low cost recompletion candidate that could greatly extend our Jumpbush production profile for years to come.

Ongoing development

Last year, Petrobank continued to strengthen the Jumpbush/Milo asset by acquiring 5,552 net acres of land; shooting 16 square kilometres of 3-D and 48 kilometres of 2-D seismic; and drilling 50 wells (42.3 net), all successful, on acreage outside of the Siksika Nation. Overall, the ongoing development plan entails drilling 50+ wells per year. Drilling plans for 2007 are still being confirmed as the First Nation is re-evaluating its longer-term growth targets and approval processes, and as Petrobank optimizes the best use of capital across our diverse opportunity base.





● 100% WI wells drilled to date ■ Petrobank land

BAKKEN RESOURCE PLAY, SOUTHEAST SASKATCHEWAN

LAND BASE AT 12/31/06	62,448 acres gross (49,105 net) average 79 percent working interest
WORKING INTEREST	12.5 to 100 percent
PRODUCING WELLS	8 at 100 percent working interest (6 currently being completed), and 11 (2.36 net) non-operated wells
PRODUCTION PERCENTAGE	Bakken production of 210 bopd, represented only 6.8 percent of Canadian Business Unit production during 2006 but had increased to approximately 25 percent in December with the addition of our initial wells drilled at 100 percent working interest

- 90 percent success rate
- February 2007 production 1,090 bopd
- 2006 drilling: 8 horizontal - 100 percent working interest - operated wells and 8 (1.8 net) non-operated wells
- Increased land base to 73,985 acres (59,014 net) early in 2007
- 2007 drilling: 40, 100 percent working interest, operated wells

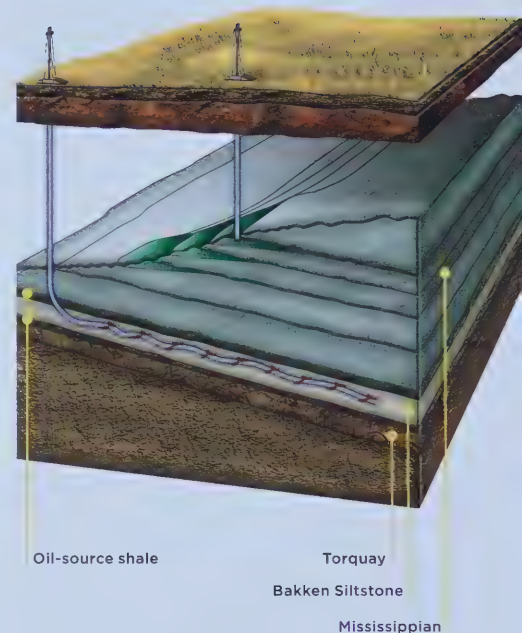


Emerging Bakken resource play

The Bakken formation is found in the Williston Basin, underlying much of North Dakota, eastern Montana and extending up into southern Saskatchewan. Unlike the conventional Mississippian oil resources in this area of Saskatchewan, which accumulate in distinct reservoirs, the Bakken is an extensive regional resource play with the oil contained mostly in siltstones and thin sandstone reservoirs with low porosity and permeability. The Mississippian-aged Bakken formation, found between two tight horizons, is capable of high production rates and yields sweet, light oil with a 41 degree gravity, and liquids-rich gas. The resource is significant with approximately 4.5 million barrels of original oil-in-place per section of land in the greater play area.

The key to unlocking the potential in the Bakken has been advances in horizontal well techniques, particularly the application of new horizontal fracturing and completion technologies. Essentially, the drilling of long horizontal wells allows maximum exposure to the reservoir, and new completion techniques allow fracturing of the siltstone along the extent of the wellbore. Until the introduction and validation of these technologies, the Bakken was generally not considered economically viable.

The Bakken play is relatively new in Canada, but has been highly successful in the United States portion of the basin where, since 2000, drilling activity has increased dramatically and geologists with the United States Geological Survey are now estimating 413 billion barrels of original oil-in-place in the Bakken. In Canada, Bakken activity has been more limited, starting only in 2004 with about seven rigs working continuously versus approximately 20 rigs working the U.S. side of the play. Different players in Canada are using slightly different drilling and completion techniques, which have yielded widely different results.

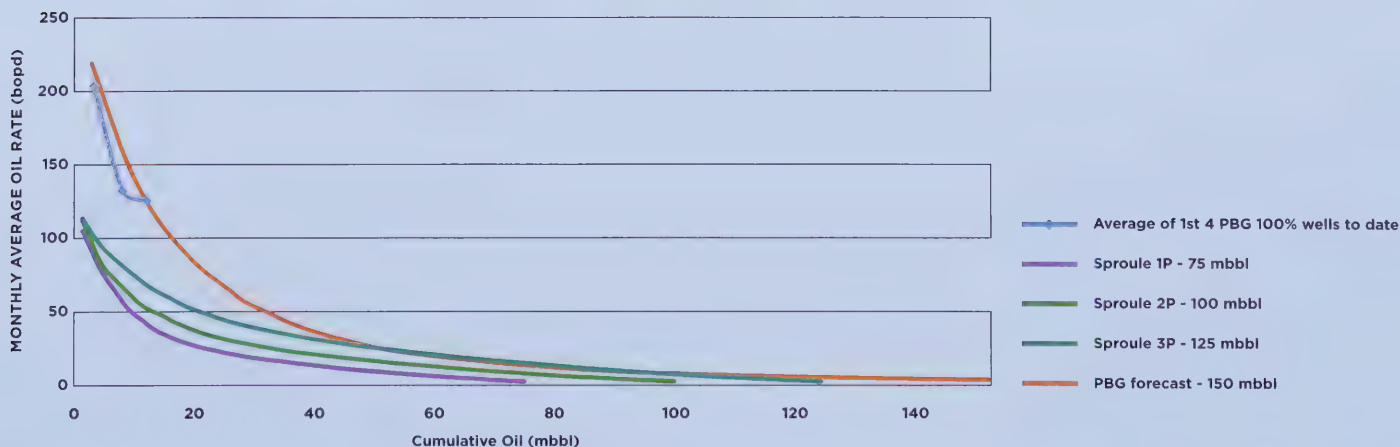


Petrobank's competitive advantage

Petrobank's extensive undeveloped land position includes non-expiring fee simple lands in Saskatchewan and Manitoba. In 2005, the Company farmed-out lands in southeast Saskatchewan to a company pursuing the Bakken play in exchange for a combination of royalty interests and carried working interests. This strategy enabled Petrobank to monitor the early technical development of the play with no capital risk. Based on that vantage point, the Company developed its own operational drilling, completion and fracture stimulation strategies, which were tested with eight horizontal wells, evaluating alternative approaches for efficient capture of this large resource base.

Of the eight horizontal wells drilled in 2006 by Petrobank, seven were successful. The first four producers came on-stream at over 250 bopd and, in the first three months of production, have already produced more than 12,000 barrels per well. Each of these successful wells has yielded at least three follow-up development locations to be drilled through 2007.

BAKKEN PER WELL FORECASTED PRODUCTION AND RESERVES





The economics are attractive in the Bakken play. At least four wells per section can be drilled. Drilling and completion costs are approximately \$1.7 million per well, and according to our independent reserve evaluator, proved plus probable reserves are 100,000 barrels of oil per well, representing less than 10 percent recovery of original oil-in-place, are well below our internal estimates of well potential. This leaves considerable upside potential for improved recoveries. The economics are further enhanced by high realized oil prices due to the high quality oil and the Saskatchewan government's royalty holiday of 35,000 barrels per well.

High growth in 2007

Our first non-operated wells were brought on-stream in 2004. With last year's drilling Bakken production increased to 910 bopd in December 2006 and further to 1,090 bopd in February 2007. With this rapid production growth, 2007 will see a concentrated drilling program in the Bakken, with at least 40 horizontal wells planned and two rigs dedicated to the program. Our growing inventory of locations now exceeds 200 and we will soon be constructing a Petrobank-operated battery in our main producing area.

At the end of 2006, the Company's land base in the area with Bakken potential totaled 62,448 acres (49,105 net). Since then, we have been aggressively adding to our land base with the negotiation of a farmin on 5,760 acres (5,574 net), and the acquisition of an additional 5,777 acres (4,335 net). To further our competitive advantage in this high growth play, Petrobank plans to continue acquiring strategic lands through Crown sales, acquisitions and farm-ins.

TORQUAY PLAY, SOUTHEAST SASKATCHEWAN AND MANITOBA

LAND BASE	93,000 acres (87,000 net)
WORKING INTEREST	94 percent

Petrobank is evaluating the potential of the Torquay formation, another siltstone play similar to the Bakken, however, it is found in deeper Devonian-aged rocks. To date, Petrobank has tested the play with 10 vertical wells (100 percent working interest), which yielded high initial rates of production but with steep declines. Reservoir parameters suggest large amounts of original oil-in-place and we are currently evaluating optimal drilling and completion techniques to obtain maximum recovery rates. Further evaluation is likely to be undertaken with horizontal wells, however, with Petrobank's ongoing success in the Bakken play, that will remain the business unit's main focus of activity in 2007.

NORTHWEST ALBERTA EXPLORATION

LAND BASE	7,040 acres
WORKING INTEREST	100 percent

- Acquired 30 square kilometres of 3-D seismic and a further 23 square kilometre 3-D seismic program is planned later in 2007
- Plan to drill at least two, 100 percent working interest, wells in 2007

Petrobank is balancing its lower risk activities with higher impact exploration potential in one of the more exciting industry plays in recent years. In 2006, Petrobank acquired Crown lands to gain entry to a new exploration area in northwest Alberta with the main targets being light sweet oil and natural gas opportunities in stacked horizons. From regional mapping and 3-D seismic acquired in 2007 over the most prospective lands, Petrobank's exploration lands appear to be on trend with recent large discoveries in the area. We have acquired 11 sections of land encompassing various play types and we plan to drill our first two exploration wells in the second and third quarters of 2007.

RED WILLOW & HACKETT, ALBERTA

Red Willow is an attractive property for Petrobank due to the high average working interest, high deliverability gas targets, the large number of drilling opportunities and excellent infrastructure. The primary drilling targets are the Glauconite and Ellerslie zones within the Mannville Group and most wells drilled are 100 percent working interest. In 2006, Petrobank drilled nine wells, resulting in six gas wells. The best wells were the last four gas wells drilled late in 2006 and brought on-stream late in 2006 and January of 2007. In 2007, Petrobank plans to drill up to three wells in the area and work is being done to optimize our gas plant and oil battery.

PRINCETON, BRITISH COLUMBIA

Princeton is an area with significant coal bed methane (CBM) potential. Petrobank and its partner control the coal and petroleum and natural gas rights over the Princeton Basin and evaluation of the CBM opportunity is ongoing.

Plans call for two wells (1.2 net) in the basin in 2007 to demonstrate commercial gas rates from the coals in this long-term development project.

ENVIRONMENT AND COMMUNITY RELATIONS

Petrobank creates strong relationships in all the communities in which we are active. Specifically, our operations at Jumbush and at Princeton reflect our commitment to community engagement and dialogue.

At Jumbush, Petrobank is continuing a constructive relationship with the Siksika Nation, represented by the Siksika Energy and Resource Corporation (SERC) and their resource management agency, Siksika Land Management Service Area (LMSA). Our open and professional relationship with SERC, a 30 percent partner at Jumbush, is an important factor in our effective and timely development of the Jumbush field. The Nation's insight continues to ensure our Jumbush operations are both productive and sensitive to the environmental and cultural realities of the area. Petrobank and its partner SERC will again continue our successful employment and training program after the Siksika Nation has finalized its new approval processes and desired level of activity. Siksika Nation members and contractors will continue to be employed for their expertise in all areas of our business, especially pipelining. Moreover, these contractors provide safe, competitive services while generating employment and economic benefits for the community.

Petrobank recognizes that successful follow-up drilling in the Princeton area to evaluate the CBM potential of this basin will depend on open and frequent dialogue with the local community and its representatives. In the past, we have maintained this dialogue through public presentations, media relations and a series of education-focused newspaper placements. This community engagement will again be paramount so that the local community is comfortable with Petrobank's plans and our safeguards to protect the environment.

Community understanding of CBM also relies on an understanding of how government and industry work together to protect community interests, and Petrobank will continue to share information about this important relationship.

At Princeton, Petrobank is maintaining its relationship with the Upper Similkameen Indian Band with the intention of developing local employment and business opportunities for members of the Band and local area residents, when we convert the project to a commercial development.

Petrobank's environmental management approach remains committed to meeting or exceeding government requirements while following, and setting, best industry practices.





The introduction of Colombia's new fiscal and land tenure regimes in 2004 reinvigorated the Colombian oil industry. Petrominerales reacted quickly and we are now one of Colombia's largest exploration land holders with 13 contracts covering 1.5 million acres.

A CHANGING COLOMBIA

The political and investment landscape has been changing rapidly in Colombia. In 2002, the election of President Alvaro Uribe marked a turning point for the country's economy, and its past reputation as a hotbed of narco-terrorism. A second factor was the negotiation of a free trade agreement with the United States which reaffirmed the government's commitment to open market policies. Colombia is now considered by many to be an oasis in a desert of Latin American uncertainty.

Under President Uribe, the government began to pro-actively pressure extremist groups involved in narco-trafficking to disband and lay down their weapons or risk armed intervention by the State. This has led to significant declines in violence in general, and a significant reduction in attacks against government facilities, including oil and gas infrastructure. The turnaround is being seen in the economy and foreign investment. In early 2006, Standard & Poor's upgraded the country's sovereign credit rating to BB positive from BB stable citing, "growth prospects are largely a result of significant and sustained improvement in domestic security that ... [has] led to renewed domestic confidence and double-digit growth in private investment."

Colombia has experienced the longest period of uninterrupted foreign direct investment in Latin America, which is expected to reach approximately US\$6.0 billion in 2006. The largest investments have been in the mining industry (46 percent) and the oil and gas sector (34 percent).

The oil landscape

Colombia is one of the largest oil producers in Latin America, and it still has vast and largely under-explored hydrocarbon resources. Crude oil accounts for approximately 10 percent of the country's revenues and nearly 30 percent of exports, primarily to the U.S. However, Colombia's crude oil output had been declining due to a lack of investment through the end of the 1990s, and the country was on the road to becoming a net importer of oil. Domestic production peaked at 800,000 bopd in 1999 and had fallen to 526,000 bopd by 2005. To reverse that trend, the Colombian government introduced new and attractive fiscal terms to encourage foreign investment by exploration and production companies.

Industry being rejuvenated

In 2004, the government took the first step to foster re-investment in the petroleum industry with the creation of the Agencia Nacional de Hidrocarburos (ANH), the national hydrocarbon agency with the mandate to administer new exploration lands and encourage foreign investment. Then the ANH introduced a new land tenure system.

The results speak for themselves. Today, there are over 70 oil and gas companies operating in Colombia, and ANH predicts a 50 percent increase in exploration spending over last year to US\$750 million. Since the ANH was formed, over 130 land contracts have been signed and, in 2006 alone, almost 26,500 km of 2-D seismic was acquired. By comparison, from 1995 to 2000, the annual average was only 11 land contracts and approximately 1,300 km of 2-D seismic. This year about 85 new field wildcats will be drilled, up from 42 in 2005 and 56 in 2006.

Attractive land tenure

Under the previous regulatory framework, the industry operated under joint ventures with the state-owned oil company, Ecopetrol. These contracts allowed Ecopetrol to back-in for up to 50 percent of any new commercial discovery.

The new fiscal regime is structured around exploration and production (E&P) contracts and Technical Evaluation Agreements (TEAs) entered into directly with the ANH and without any participation by Ecopetrol.

TEAs allow companies to conduct preliminary evaluation of large areas prior to committing to full-scale exploration. TEAs are typically large land blocks and entail minimal initial work commitments, such as reevaluating existing data with a view to defining prospects and ultimately committing to an E&P contract.

With E&P contracts the initial contract period typically runs for six years of exploratory activity, with the possibility of a four-year extension, and includes a reasonable exploration work plan. There are no initial land costs and inexpensive annual land rentals. Companies obtain access to all available geological and geophysical data, and first phase work commitments usually involve shooting new seismic. The contracts can typically be held by simply drilling one well per year after the first phase, or can be relinquished at any time at the Company's option.

Once commerciality of a field is declared, the development phase lasts an additional 25 years, which can be extended in certain circumstances for another 10 years, or for the life of the reserves. These new terms provide a company with the right to all reserves and production from newly discovered fields, subject to an attractive sliding scale royalty, which is initially fixed at eight percent. In addition, corporate income taxes are scheduled to decline to 33 percent by 2008, from 38.5 percent.

New swaths of land up for auction

Later in 2007, the ANH will be putting some of the few remaining spreads of open acreage up for auction in a number of bid rounds, including the Caribbean offshore, the Pacific Basin in western Colombia and the extensive heavy oil belt in the southern and eastern reaches of the Llanos Basin. These rounds are expected to be based on somewhat less attractive fiscal terms, with higher minimum work commitments, and the unusual step of having the winner decided on the percentage royalty the operator and partners are willing to pay.





Operations

OVERVIEW

Petrominerales was already operating in Colombia when the new contracting and fiscal regimes were introduced in 2004. Recognizing the potential, the Company captured a significant exploration land base. Today we are one of the country's largest onshore exploration landholders at 1.5 million acres. Our lands are held in two producing fields and 13 exploration blocks in the highly prospective Llanos, Upper Magdalena, and Putumayo Basins.

Petrominerales commenced production under two incremental production contracts (IPC's) in 2003; Orito in the Putumayo Basin and Neiva in the Upper Magdalena Basin. At Orito, drilling over the past two years has proven a significant southwest extension to the field, and nine new wells are planned at Orito in 2007. At Neiva, development activities will include the drilling of six new wells in 2007 and building on our recent success in improving production from existing wells with recompletions and fracture stimulations.

On the exploration front, we have to date acquired 3-D seismic over five of our exploration blocks, which has led to the identification of 21 initial leads and prospects. In 2007, we will be drilling five exploratory wells targeting oil pools with the potential for 3 to 25 mmbbl each.



Near-term development potential

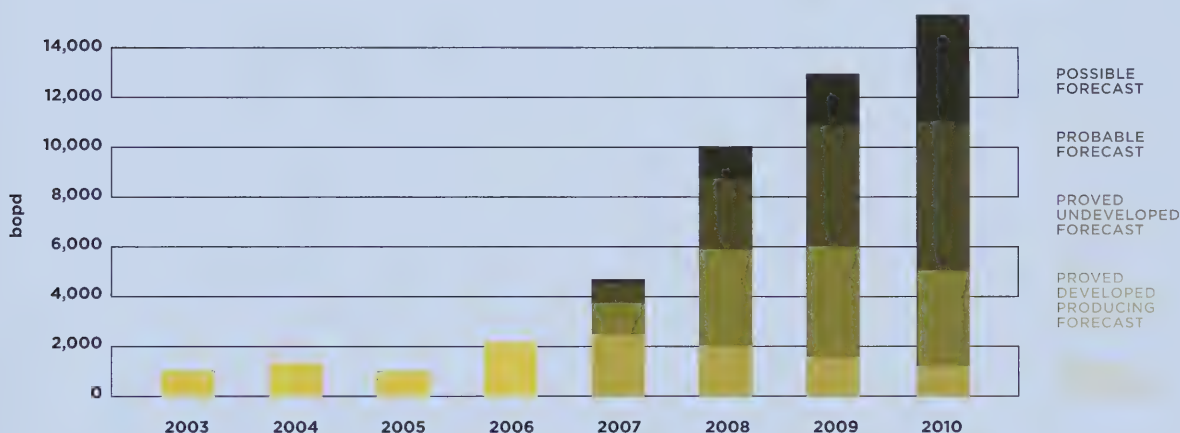
The majority of our existing production comes from the giant Orito field in the Putumayo Basin, which produces light oil from multiple horizons. Development is ongoing after our drilling program proved up a significant extension to the field. Our first exploration well on the adjacent Las Aguilas block will be drilled in 2007, which could significantly increase our development drilling inventory.

The Upper Magdalena Valley Basin contains our Neiva field, which produces medium quality oil and is undergoing redevelopment through drilling and recompletions.

The Company's independent reserves evaluators have estimated our remaining working interest proved plus probable plus possible reserves from Orito and Neiva at 33.9 mmbbl and production is forecast to increase to over 15,000 bopd by the end of 2010.

OUR NEAR-TERM DEVELOPMENT TARGET IS TO BE PRODUCING 10,000 BOPD WITHIN THE NEXT TWO YEARS FROM OUR ORITO AND NEIVA FIELDS.

AVERAGE DAILY PRODUCTION



Sustainable exploration potential

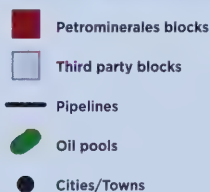
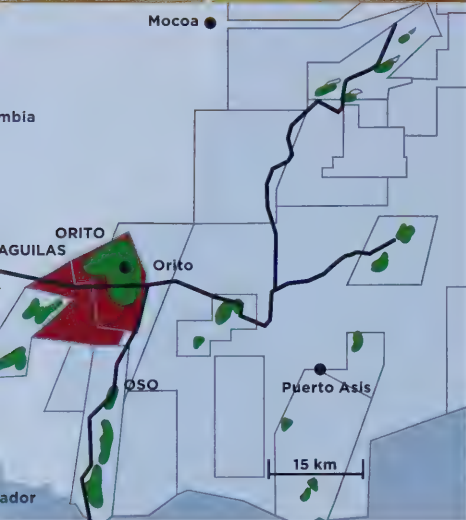
The Llanos Basin has large tracts of unexplored land in a plains region with geological similarities to the depositional patterns in Western Canada. The basin generally yields light, sweet oil and our drilling prospects are targeting 3 to 25 mmbbl pools, with high potential initial productivity per well of over 1,000 bopd.

Our goal is to discover and develop a 10,000 bopd production platform from our highly prospective Llanos Basin land base over the next three to five years.

Long-term heavy oil potential

There is evidence of a significant belt of heavy oil extending through Colombia that could be aerially as large as the giant Faja del Orinoco region in Venezuela.

Our longer-term goal for this part of our portfolio is to develop one or more significant (10,000 to 50,000 bopd) heavy oil projects using the THAI™ technology, or other heavy oil technologies.



Near-term development potential

ORITO

Orito geology

The Orito field, almost 43 square kilometres in area, is the largest field in southern Colombia and is estimated to have originally contained in excess of 1.0 billion barrels of oil in three primary sandstone reservoirs; the Eocene Pepino, and the Cretaceous Villeta and Caballos. The most significant is the Cretaceous Caballos formation, which is estimated to have originally contained more than 700 million barrels of oil-in-place.

The Caballos is a complex series of fluvial/deltaic and marginal marine sands and is the primary producing reservoir in the field. The Caballos zone is interpreted to have a tilted oil/water contact that originally dipped from northeast to southwest at least 280 metres within the field. Crude quality varies from near 30° API in structurally low areas to as high as 43° API in the northern, up-dip areas of the field.

The recently updated reserves work of DeGolyer and McNaughton delineates 27.9 million gross working interest barrels of proved, probable and possible reserves to be developed at Orito, and the Company anticipates an additional 42 wells to be drilled. To date, the field's three reservoirs have produced 228 million barrels of oil, or approximately 22 percent of the original oil-in-place. The Caballos reservoir has produced 188 million barrels gross, or 82 percent of the field's total production since it was discovered in 1963.

Strategy

Petrominerales acquired the Orito IPC in 2001, which included access to all existing infrastructure and data. At that time, Orito production had declined to 3,500 bopd from a peak rate of 82,000 bopd in 1970, principally as only minor exploitation and no secondary recovery schemes had been implemented on the field.

Our main drilling target at Orito is the Caballos reservoir, a 'combination drive' reservoir. Typically these reservoirs exhibit higher than normal rates of recovery. We believe it is possible to improve field recovery to 30-40 percent of original oil-in-place (currently 22 percent) which, at maximum recovery, could add more than 100 million barrels of gross potential reserves from the Caballos formation. To enhance production and improve recovery rates, we are executing an extensive development drilling program, installing high volume lift electrical submersible pumps (ESP) and re-completing wells to enhance flow rates. With ESPs, we are targeting approximately 500 bopd from new wells drilled into the field. We are also implementing a program of segregated fracture stimulations targeting specific sands in the Caballos formation. Typical well depths are 7,500 feet and the costs for drilling and completion are approximately US\$6.0 million per well.

2007 Program

In 2007, we plan to drill nine new wells at Orito. Currently, one drilling rig is on location and our second contracted rig will be mobilized to Orito in mid-2007 after it completes our Llanos Basin exploration drilling program. In addition, we plan to continue our recompletion and fracture stimulation program in at least six additional wells.

To complement the Orito development program, we will also be drilling our first exploratory well on the adjacent Las Aguilas block in 2007. Success on that well could prove up a further extension of the Orito field and up to 15 follow-up development locations.

NEIVA

Overview

The Neiva field is located in the Upper Magdalena Valley Basin, where we are partnered in an IPC with Ecopetrol. The field reached peak production of 7,000 bopd in the early 1980s, and the multi-zone reservoirs are suitable for low-risk exploitation. Average initial flow rates for new wells are approximately 80 to 150 bopd, and our fracturing program has resulted in improved productive capability on existing producing wells. A secondary recovery waterflood is also being initiated.

In 2006, we completed our second full year of the 19-year complimentary phase of the IPC. To date, we have drilled seven wells into the Honda formation, one well into the Doima/Chicoral formation and have performed 16 workovers.

Neiva geology

Neiva production is primarily from a series of thick Tertiary sandstones in the Honda formation totaling approximately 800 feet of pay at a maximum depth of 3,500 feet. We have also developed production from the slightly deeper Doima-Chicoral reservoir, which is a thick, conglomerate trapped along the flank of the main Neiva structure as an angular unconformity.

Activity

In 2006, we completed our initial phase of fracture stimulations involving five test wells in the Honda and Doima-Chicoral reservoirs. The DT-56 (Doima-Chicoral) stimulation was highly successful, doubling gross oil production rates to 170 bopd from 86 bopd. The Honda formation fracture stimulations included installation of progressive cavity pumps which have initially resulted in significant increases in production.

2007 Plans

Based on positive initial results, we plan to drill three wells targeting the Doima formation, and three wells targeting the Honda formation. We will continue to monitor the Honda fracture stimulations and expect to expand this program to more than 50 locations. In addition, a pilot waterflood is in the initial implementation stage. Two wells were recently converted to water injectors as part of this pilot water flood program in the Honda reservoir. Water injection commenced in early November 2006 and we have already seen a slight increase in fluid levels and oil production in nearby wells.

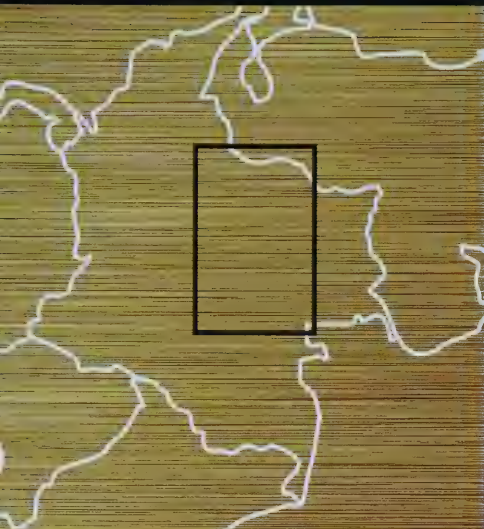
Sustainable exploration potential

EXPLORATION OVERVIEW

The Llanos Basin is located in an area with topography similar to Western Canada. A mountain range, the Eastern Cordillera of the Andes, bounds the basin to the west with extensive plains to the east. The regional geology also has parallels to the Western Canadian Sedimentary Basin. While it is not possible to template exploration exactly between the two regions, a key to exploration is the ability to transfer Canadian geo-technical evaluation techniques and technology to the largely under-explored Colombian basins. We also believe that certain exploration concepts commonly understood in the Canadian industry can be applied in Colombia.

In Canada, a large base of geological and geophysical data extending back over 60 years is publicly available for analytical and prospect development purposes. There is also an extensive private database of seismic. Petrominerales has been one of the first companies in Colombia to extensively employ 3-D seismic as an exploration tool, and utilize advanced reprocessing techniques on existing 2-D seismic. Our ability to incorporate advanced Canadian technology into Colombia at an earlier stage of oil development is clearly a competitive advantage for Petrominerales.





IN ADDITION TO OUR NEAR-TERM DEVELOPMENT POTENTIAL, OUR GOAL IS TO DISCOVER AND DEVELOP A 10,000 BOPD PRODUCTION PLATFORM FROM OUR HIGHLY PROSPECTIVE LLANOS BASIN LAND BASE OVER THE NEXT THREE TO FIVE YEARS.

The Llanos Basin is an attractive exploration focus area for Petrominerales as large land blocks can be retained with no initial land payments and with a reasonable level of work commitments, often by simply drilling one exploration well per year per block. This provides considerable flexibility in planning exploration programs and the strategic assessment of our lands based on firm drilling results.

Exploration strategy

Petrominerales has completed the first phase of exploration commitments, which included reprocessing 2-D seismic, acquiring new 3-D seismic and interpretation of existing data on key prospective portions of the first five of our exploration blocks. Seismic interpretation has now led to the identification of 21 initial leads and prospects.

One option for obtaining initial access to large exploration areas in Colombia is with a TEA (Technical Evaluation Agreement) which requires very low initial work commitments, typically reevaluation of existing data with a view to identifying an exploration block and then relinquishing the remaining acreage. We initially used this mechanism to evaluate areas covered by five large TEAs. Accordingly, our total acreage position has fluctuated as portions of these five areas have been converted to exploration contracts.

Beginning in January 2007, we began a five-well drilling program to test the initial prospects on each of the Casanare Este, Casimena, Corcel and Las Aguilas blocks, as well as a second test on the Joropo block. In addition, we have signed agreements for two exploration blocks, Mapache and Castor, covering a significant portion of the original Chicago TEA and we have now proposed an additional four blocks over our old Rio Ariari, Chiguiro and Guatiquia TEAs. We have also applied for two additional blocks adjoining our Joropo block. In total, we have now finalized or are in the processes of finalizing 13 exploration contracts covering over 1.5 million acres.

- Petrominerales blocks
- Third party blocks
- Pipelines
- Oil pools
- Heavy oil belt
- Cities/Towns



LLANOS BASIN – PLAINS REGION

Llanos Basin geology

In the Llanos Basin, productive traps are formed by a series of “up to the basin” faults. Tertiary and Cretaceous sandstone reservoirs trap hydrocarbons against these faults in up to five individual sands. Production is quite often as high as 2,000 bopd per well and pools in this region of the Llanos Basin have ranged from 3 to 45 million barrels. Our initial prospects are targeting between 3 to 25 mmbbl each, most of which have been identified from our 3-D seismic.

Long-term heavy oil potential

LLANOS BASIN – HEAVY OIL BELT

A significant opportunity exists in a large heavy oil fairway located in the southern and eastern portion of the Llanos Basin. A number of fields have been discovered and are producing, although the area is largely unexplored and under-developed. The government is committed to developing this significant resource and has reserved much of this acreage for future bidding rounds which may require large initial work programs and alternative fiscal terms. Petrominerales is fortunate to have captured 0.8 million acres in this highly prospective region pursuant to three separate exploration contracts, all under Colombia's existing fiscal framework.

Like conventional oil resources in the northern Llanos Basin, the heavy oil belt has parallels to the geology in Canada's Western Sedimentary Basin. Under optimal depositional and migration patterns, this belt could extend across the entire length of the Llanos Basin, and be as large aerially as the giant Faja del Orinoco in Venezuela. Four heavy oil projects in the Venezuelan Faja del Orinoco are producing approximately 600,000 bopd. While the Venezuelan portion of the heavy oil belt is considerably more developed to date, we believe the Colombian heavy oil belt has excellent potential for future heavy oil exploitation.

ENVIRONMENT AND COMMUNITY RELATIONS

The Company completed its fourth year of field operations in Colombia with 100 percent environmental compliance in executing our exploration development programs. Our social responsibility strategies include environmental compliance and promoting fundamental relationships with local communities and the provincial and national authorities.

Petrominerales has established a community relations approach based on three principles:

- Local employment is promoted by identifying, providing and supporting job opportunities within our operating areas. This has been well received by local communities and has contributed to maintaining a positive relationship in and around our operations. Local employment opportunities are also provided by hiring local contractors for several services.
- Education and training programs are focused on strengthening the relationships between communities and the local authorities, and on helping communities identify new markets for their goods and services to reduce their dependence on the oil business. Our approach also encourages local community engagement in the government development process, and reinforces the link between oil revenues and municipal budgets.
- Community engagement creates a partnership in the preparation of environmental base line studies for local environmental management, which strengthens our relationship with communities by combining our expertise and environmental approach with local knowledge of the environment and land management. We are continuing to build a relationship of trust by encouraging communities to become involved in all aspects of our environmental management processes.

Our approach has been cited by both the government and oil industry as one of the “best practice” models to follow.

Operations statistical review

TOTAL COMPANY

Land Summary (thousands of acres)

As at December 31, 2006

	Developed		Undeveloped		Total		Average
	Gross	Net	Gross	Net	Gross	Net	WI%
Alberta	66	42	130	99	196	141	72%
Saskatchewan	4	3	153	146	157	149	95%
Other	-	-	80	59	80	59	74%
Canadian Business Unit	70	45	363	304	433	349	81%
Heavy Oil Business Unit (WHITESANDS)	-	-	40	40	40	40	100%
Latin American Business Unit (Colombia)	45	35	1,501	1,501	1,546	1,536	99%
Total Company	115	80	1,904	1,845	2,019	1,925	95%

Average Daily Production

	Oil and NGL (bbl)		Gas (mcf)		Total (boe)	
	2006 Average	Q4 2006	2006 Average	Q4 2006	2006 Average	Q4 2006
Canadian Business Unit						
Jumpbush	28	33	8,802	9,142	1,495	1,557
Red Willow	166	106	2,983	1,563	663	367
SE Saskatchewan	409	727	22	60	413	737
Other	315	399	1,132	1,202	504	599
Total Canadian Business Unit	918	1,265	12,940	11,968	3,075	3,260
Latin American Business Unit (Colombia)						
Orito	1,875	2,091	-	-	1,875	2,091
Neiva	319	281	-	-	319	281
Total Latin American Business Unit	2,194	2,372	-	-	2,194	2,372
Total Company	3,112	3,637	12,940	11,968	5,269	5,632

Bitumen volumes are excluded from average daily production as WHITESANDS operations are considered to be in the development stage and accordingly revenues are offset against capitalized costs.

2006 Capital Expenditures by Business Unit

(000s)	Canada	Colombia	Heavy Oil	Total Company
Drilling and completions	\$ 51,971	\$ 47,012	\$ 3,951	\$ 102,934
Facilities and equipment	11,560	5,390	18,443	35,393
Land	14,950	-	20,545	35,495
Seismic	4,437	8,076	2,371	14,884
Workovers	2,737	19,757	9,773	32,267
Capitalized interest	-	-	3,354	3,354
Other	2,378	2,988	-	5,366
Total capital expenditures	88,033	83,223	58,437	229,693
Government assistance	-	-	(3,136)	(3,136)
Investment tax credits	-	-	(4,660)	(4,660)
Net capital expenditures	\$ 88,033	\$ 83,223	\$ 50,641	\$ 221,897

Company Interest Reserves and Resources by Business Unit ⁽¹⁾ - Forecast Prices

	Canada (mboe)	Latin America (mbbl)	Heavy Oil (mbbl)	Total Company (mboe) ⁽²⁾
Developed producing	3,050	3,947	-	6,236
Total proved	6,675	13,563	-	17,624
Proved + probable (2P)	9,148	24,531	25,290	50,195
Proved + probable + possible (3P)	12,726	33,906	70,323	99,170
Best estimate contingent resources	-	-	574,060	482,210
2P + best estimate contingent resources	9,148	24,531	599,350	532,406

(1) Throughout the tables in this operations statistical review, Company interest reserves and resources represent 100 percent of the business unit's gross working interest, unless otherwise noted.

(2) Total Company includes Canadian Business Unit reserves as at December 31, 2006, Petrobank's 80.73 percent share of the Latin American Business Unit's reserves as at December 31, 2006, and the Company's 84 percent share of WHITESANDS Insitu Ltd. reserves and best estimate contingent resources included in the Heavy Oil Business Unit as at March 1, 2007.

Net Asset Value

(millions, except per share amounts)

December 31,	2006
NPV by business unit	
Heavy Oil ⁽¹⁾	\$ 1,310.9
Canada ⁽²⁾	150.2
Latin America ⁽³⁾	490.9
Undeveloped land ⁽⁴⁾	116.2
Seismic (at cost)	13.0
Net debt	(40.5)
Net asset value	\$ 2,040.6
Common shares outstanding	72.1
Net asset value per basic common share	\$ 28.30
Net asset value per diluted common share ⁽⁵⁾	\$ 27.10

(1) Petrobank's 84% ownership interest in the Heavy Oil business unit's probable plus possible reserves plus high estimate contingent resources using forecast prices discounted at 8% (before tax) as at March 1, 2007. These reserves and resources are estimated based on SAGD technology as it is the presently recognized technology used to define in-situ oil sands reserves and resources. This does not reflect the technical merits of the Company's patented THAI™ process; it is simply the only way for the Company to presently recognize a portion of the reserve and contingent resource potential on the WHITESANDS leases using industry accepted norms. Does not include value attributed to the Company's proprietary THAI™ and CAPRI™ technologies.

(2) Proved plus probable reserves using forecast prices discounted at 10% (before tax). Excludes \$43.7 million of possible reserve value.

(3) Petrobank's 80.73% ownership interest in Petrominerales Ltd.'s proved plus probable reserves using forecast prices discounted at 10% (before tax) translated at a US\$/Cdn\$ exchange rate of 0.858. Excludes \$146.7 million of possible reserve value and no reserves are assigned to Petrominerales Ltd.'s 1.5 million acre exploration land base.

(4) Valued at \$150/acre in Canada and US\$50/acre in Colombia.

(5) Assumes 4.4 million stock options and deferred common shares are exercised for proceeds of \$32.6 million.

HEAVY OIL BUSINESS UNIT

Company Interest Reserves and Resources - Forecast Prices

As at March 1, 2007

Based on DilBit Blending Scenario	Bitumen (mbl)
Probable reserves (2P)	25,290
Probable + possible reserves (3P)	70,323
Low estimate contingent resources	405,263
Best estimate contingent resources	574,060
High estimate contingent resources	728,491
2P + low estimate contingent resources	430,553
2P + best estimate contingent resources	599,350
2P + high estimate contingent resources	753,781
3P + low estimate contingent resources	475,586
3P + best estimate contingent resources	644,383
3P + high estimate contingent resources	798,814

Net Present Value - Forecast Prices

As at March 1, 2007

Based on DilBit Blending Scenario	Before Tax (\$millions)				After Tax (\$millions)			
Net Present Value Discounted at:	0%	5%	8%	10%	0%	5%	8%	10%
Probable reserves (2P)	92.6	8.1	(24.7)	(41.4)	74.1	(3.0)	(33.0)	(48.3)
Probable + possible reserves (3P)	742.1	310.1	176.1	114.8	514.6	202.7	104.9	60.0
Low estimate contingent resources	3,120.0	829.7	225.6	(17.0)	2,110.6	419.9	(20.8)	(194.7)
Best estimate contingent resources	6,424.2	1,881.6	831.9	428.6	4,337.2	1,148.5	415.8	136.9
High estimate contingent resources	10,578.0	2,924.9	1,384.5	822.1	7,142.8	1,873.2	815.5	431.0
2P + low estimate contingent resources	3,212.6	837.8	200.9	(58.4)	2,184.7	416.9	(53.8)	(243.0)
2P + best estimate contingent resources	6,516.8	1,889.7	807.2	387.2	4,411.3	1,145.5	382.8	88.6
2P + high estimate contingent resources	10,670.6	2,933.0	1,359.8	780.7	7,216.9	1,870.2	782.5	382.7
3P + low estimate contingent resources	3,862.1	1,139.8	401.7	97.8	2,625.2	622.6	84.1	(134.7)
3P + best estimate contingent resources	7,166.3	2,191.7	1,008.0	543.4	4,851.8	1,351.2	520.7	196.9
3P + high estimate contingent resources	11,320.1	3,235.0	1,560.6	936.9	7,657.4	2,075.9	920.4	491.0

CANADIAN BUSINESS UNIT

2006 Drilling Program

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Canadian Business Unit						
Oil	3.0	3.0	25.0	18.8	28.0	21.8
Natural Gas	9.0	8.4	49.0	41.4	58.0	49.8
Successful	12.0	11.4	74.0	60.2	86.0	71.6
Dry	7.0	6.0	2.0	2.0	9.0	8.0
Total Canadian Business Unit	19.0	17.4	76.0	62.2	95.0	79.6
Success rate	63%	66%	97%	97%	91%	90%

Company Interest Reserves ⁽¹⁾ - Forecast Prices

	Natural Gas (mmcf)	Light and Medium Oil (mmbbl)	Heavy Oil (mmbbl)	NGL (mmbbl)	Total (mboe)
Developed producing	12,864	858	14	34	3,050
Total proved	30,956	1,425	14	77	6,675
Proved + probable	39,257	2,460	17	128	9,148
Proved + probable + possible	53,544	3,433	129	240	12,726

(1) Royalty income volumes are excluded from Company gross reserves noted above but are included in net reserves and net present values. Production in the fourth quarter of 2006 included 491 boepd of royalty income production.

Reserve Reconciliation - Forecast Prices (mboe)

	Total Proved	Proved + Probable	Proved + Probable + Possible
December 31, 2005 reserves	7,372	11,635	16,188
2006 production, net of royalty income	(957)	(957)	(957)
Discoveries	904	1,547	1,605
Extensions	1,290	1,666	1,888
Technical revisions	(1,416)	(3,569)	(4,437)
Economic factors	(518)	(1,174)	(1,561)
December 31, 2006 reserves	6,675	9,148	12,726

Net Present Value - Forecast Prices

As at December 31, 2006

	Before Tax (\$ millions)				After Tax (\$ millions)			
	0%	5%	10%	15%	0%	5%	10%	15%
Developed producing	105.9	91.3	81.0	73.3	105.9	91.3	81.0	73.3
Total proved	174.2	135.1	110.4	93.6	166.7	131.3	108.4	92.5
Proved + probable	262.8	191.1	150.2	123.9	229.2	171.3	137.2	114.8
Proved + probable + possible	384.5	257.5	193.9	156.0	314.7	217.3	167.1	136.4

LATIN AMERICAN BUSINESS UNIT

2006 Drilling Program

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Latin American Business Unit (Colombia)						
Oil	-	-	6.0	4.7	6.0	4.7
Dry	1.0	1.0	-	-	1.0	1.0
Total Latin American Business Unit	1.0	1.0	6.0	4.7	7.0	5.7
Success rate	0%	0%	100%	100%	86%	83%

Company Interest Reserves ⁽¹⁾ - Forecast Prices

	Light and Medium Oil (mbbl)
Developed producing	3,947
Total proved	13,563
Proved + probable	24,531
Proved + probable + possible	33,906

(1) The Company gross reserves noted above do not include any reserves for the Company's exploration blocks.

Reserve Reconciliation - Forecast Prices (mbbl)

	Total Proved	Proved + Probable	Proved + Probable + Possible
December 31, 2005 reserves	9,582	16,085	22,263
2006 production	(801)	(801)	(801)
Net revisions	4,782	9,247	12,444
December 31, 2006 reserves	13,563	24,531	33,906

Net Present Value - Forecast Prices

As at December 31, 2006

	Before Tax (US\$ millions)				After Tax (US\$ millions)			
	0%	5%	10%	15%	0%	5%	10%	15%
Developed producing	179.2	153.1	133.7	118.8	178.8	152.8	133.5	118.6
Total proved	497.7	391.6	316.4	261.2	395.9	316.7	259.4	216.7
Proved + probable	858.7	660.5	521.8	421.3	636.1	493.7	392.9	319.1
Proved + probable + possible	1,166.9	876.8	677.7	536.1	841.5	636.3	494.3	392.5

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(2) Member of the Audit Committee

(3) Member of the Reserves Committee

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**McDaniel & Associates
Consultants Ltd.**
Calgary, Alberta, Canada

Sproule Associates Limited
Calgary, Alberta, Canada

EXCHANGE LISTINGS

The Toronto Stock Exchange
SYMBOL: **PBG**

Oslo Børs
SYMBOL: **PBG**

Pink Sheets
SYMBOL: **PBEGF**

SECURITIES FILINGS

www.sedar.com
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Vice President Finance

Doreen M. Scheidt
Corporate Controller

R. Gregg Smith
Vice President Canada

Forward-Looking Statements

This report contains forward-looking statements that are generally identifiable by terms such as anticipate, believe, budget, intend, estimate, expect, outlook, plan or other similar words, and include future capital investment plans. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; the ability to economically test, develop and utilize the Company's patented technologies, the feasibility of the technologies; and other factors, many of which are beyond the control of the Company. There is no representation by Petrobank that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

BOE conversions are presented at six mcf = one barrel.

Produced and designed by: Communication Incorporated and Cheryl Starr Design Group Inc

ABBREVIATIONS

2P	proved plus probable
3P	proved plus probable plus possible
ANH	National Hydrocarbon Agency (Colombia)
bbl(s)	barrel(s)
bcf	billion cubic feet
boe	barrel of oil equivalent
bopd	barrels of oil per day
boepd	barrels of oil equivalent per day
bpd	barrels per day
CBM	coal bed methane
GJ	Gigajoules
IPC	Incremental Production Contract
IPO	initial public offering
km	kilometres
m	metres
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcfpd	mcf per day
mmbtu	millions of British thermal units
mmcf	million cubic feet
NPV	net present value
NGL	natural gas liquids
P+P	proved + probable
TEA	Technical Evaluation Area
WI	working interest
WTI	West Texas Intermediate

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2006

**MANAGEMENT'S
DISCUSSION AND ANALYSIS**

**CONSOLIDATED
FINANCIAL STATEMENTS**



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2006

**MANAGEMENT'S
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**STRENGTH
IN OUR RESOURCES**



PETROBANK
ENERGY AND RESOURCES LTD.

PETROBANK ENERGY AND RESOURCES LTD. IS A CALGARY-BASED OIL AND NATURAL GAS EXPLORATION AND PRODUCTION COMPANY WITH OPERATIONS IN WESTERN CANADA AND COLOMBIA. THE COMPANY OPERATES HIGH-IMPACT PROJECTS THROUGH THREE BUSINESS UNITS. THE CANADIAN BUSINESS UNIT IS DEVELOPING A SOLID PRODUCTION PLATFORM FROM LOW RISK GAS OPPORTUNITIES IN CENTRAL ALBERTA ALONG WITH A LIGHT OIL RESOURCE PLAY IN SOUTHEAST SASKATCHEWAN, COMPLEMENTED BY NEW EXPLORATION PROJECTS AND A LARGE UNDEVELOPED LAND BASE. THE LATIN AMERICAN BUSINESS UNIT IS OPERATED BY PETROBANK'S 80.7 PERCENT OWNED, TSX-LISTED SUBSIDIARY, PETROMINERALES LTD. (TRADING SYMBOL: PMG), WHICH PRODUCES OIL THROUGH TWO INCREMENTAL PRODUCTION CONTRACTS IN COLOMBIA AND HAS EXPLORATION CONTRACTS COVERING 1.5 MILLION ACRES IN THE LLANOS AND PUTUMAYO BASINS. WHITESANDS INSITU LTD., PETROBANK'S 84 PERCENT OWNED SUBSIDIARY, OWNS 39,680 ACRES OF OIL SANDS LEASES WITH AN ESTIMATED 2.6 BILLION BARRELS OF BITUMEN-IN-PLACE AND OPERATES THE WHITESANDS PROJECT WHICH IS FIELD-DEMONSTRATING PETROBANK'S PATENTED THAI™ HEAVY OIL RECOVERY PROCESS. THAI™ IS AN EVOLUTIONARY IN-SITU COMBUSTION TECHNOLOGY FOR THE RECOVERY OF BITUMEN AND HEAVY OIL THAT INTEGRATES EXISTING PROVEN TECHNOLOGIES AND PROVIDES THE OPPORTUNITY TO CREATE A STEP CHANGE IN THE DEVELOPMENT OF HEAVY OIL RESOURCES GLOBALLY.

MANAGEMENT'S DISCUSSION AND ANALYSIS

SUMMARY OF ANNUAL RESULTS

	2006	2005	2004
Financial			
(\$000s, except where noted)			
Oil and natural gas revenue	99,228	65,081	73,377
Funds flow from operations ⁽¹⁾	61,425	29,152	23,397
Per share – basic (\$)	0.92	0.50	0.43
Per share – diluted (\$)	0.89	0.49	0.43
Net income	23,106	12,808	833
Per share – basic (\$)	0.35	0.22	0.02
Per share – diluted (\$)	0.33	0.21	0.02
Capital expenditures	229,693	118,152	47,901
Property dispositions	-	-	143,027
Total assets	447,531	260,982	205,392
Net debt ⁽²⁾	40,545	60,808	35,183
Common shares outstanding, end of year (000s)			
Basic	72,125	63,220	54,956
Diluted	76,538	68,451	59,758
Operations ⁽³⁾			
Canadian operating netback (\$/boe except where noted)			
Oil and NGL revenue (\$/bbl) ⁽⁴⁾	61.18	60.96	25.42
Natural gas revenue (\$/mcf) ⁽⁴⁾	6.21	8.09	5.99
Oil and natural gas revenue ⁽⁴⁾	44.40	50.84	31.84
Royalties	6.28	10.46	7.17
Production expenses	6.89	6.05	7.07
Transportation expenses	0.39	0.98	0.94
Operating netback	30.84	33.35	16.66
Colombian operating netback (\$/bbl)			
Oil revenue	61.68	53.62	43.70
Royalties	4.95	4.29	3.51
Production expenses	7.78	9.49	7.67
Operating netback	48.95	39.84	32.52
Average daily production			
Canada – oil and NGL (bbls)	918	452	1,732
Canada – natural gas (mcf)	12,940	11,810	16,196
Total Canada (boe)	3,075	2,420	4,431
Colombia – oil (bbls)	2,194	1,031	1,359
Total Company (boe)	5,269	3,451	5,790

(1) Calculated based on cash flow from operations before changes in other non-cash working capital and asset retirement obligations settled.

(2) Includes working capital (deficiency), bank debt and subordinated notes.

(3) Six mcf of natural gas is equivalent to one barrel of oil equivalent ("boe"). Bitumen volumes are excluded from average daily production as WHITESANDS operations are considered to be in the development stage and accordingly revenues are offset against capitalized costs.

(4) Canadian sales prices are shown after transportation and forward sales contracts.

The following Management's Discussion and Analysis ("MD&A") is dated March 12, 2007 and should be read in conjunction with the consolidated financial statements and accompanying notes of Petrobank Energy and Resources Ltd. ("Petrobank" or the "Company") as at and for the years ended December 31, 2006 and 2005. Additional information for the Company, including the Annual Information Form ("AIF"), can be found on SEDAR at www.sedar.com or at www.petrobank.com. In addition to historical information, the MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; costs and availability of services; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; the ability to economically test, develop and utilize the Company's patented technologies; the feasibility of the technologies; and other factors, many of which are beyond the control of the Company. Accordingly, there is no representation by Petrobank that actual results achieved during the forecast period will be the same in whole or in part as those forecast. Further, any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws.

Natural gas volumes have been converted to barrels of oil equivalent ("boe"). Six thousand cubic feet ("mcf") of natural gas is equal to one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are not considered measures under Canadian Generally Accepted Accounting Principles ("GAAP"), such as funds flow from operations, funds flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for management and shareholders. Specifically, funds flow from operations and funds flow per share reflect cash generated from operating activities before changes in non-cash working capital and asset retirement obligations settled. Funds flow from operations should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined under GAAP as an indicator of the Company's performance. Management considers funds flow from operations and funds flow per share important as they help evaluate performance as well as demonstrate the Company's ability to generate sufficient cash to fund future growth opportunities and repay debt. Net debt is used to evaluate the Company's financial leverage. Profitability relative to commodity prices per unit of production is demonstrated by operating netbacks. All amounts are in Canadian dollars, unless otherwise stated.

Highlights

- Funds flow from operations more than doubled to \$61.4 million in 2006 from \$29.2 million in 2005. On a per diluted share basis, funds flow from operations increased by 82 percent to \$0.89 in 2006 from \$0.49 in 2005.
- Recorded net income of \$23.1 million compared to \$12.8 million a year earlier. On a per diluted share basis, net income increased by 57 percent to \$0.33 in 2006 from \$0.21 in 2005.
- Production increased by 53 percent to 5,269 boe per day ("boepd") in 2006 from 3,451 boepd in 2005. Canadian Business Unit production increased by 27 percent to 3,075 boepd while production from the Latin American Business Unit increased by 113 percent to 2,194 barrels of oil per day ("bopd") in 2006.
- Conventional Canadian production during January and February of 2007 has increased further to an average of 4,192 boepd due to natural gas tie-ins late in the year and new light oil production from the Company's Bakken and Torquay properties in southeast Saskatchewan.
- Capital expenditures totalled \$229.7 million: Canada - \$88.0 million; Latin America - \$83.2 million; and Heavy Oil - \$58.4 million.

Completed construction of the facilities and produced first bitumen from the world's first THAI™ well pairs at the Company's WHITESANDS project.

On February 6, 2006 the Company issued 2.6 million common shares for gross proceeds of \$33.4 million in connection with a public offering and secondary listing on the Oslo Stock Exchange.

On June 29, 2006 the Company completed an initial public offering and TSX listing of Petrominerales Ltd. ("Petrominerales") (TSX: PMG), Petrobank's Latin American Business Unit, raising gross proceeds of \$60 million for Petrominerales and \$8.6 million for Petrobank. Petrobank continues to retain an 80.7 percent interest in Petrominerales.

- The Company repaid the remaining \$49.9 million of its nine percent subordinated notes upon maturity on July 31, 2006.
- On December 22, 2006 the Company closed an issuance of 3.0 million common shares at a price of \$17.75 per share, and 1.5 million flow-through common shares at a price of \$23.00 per share for gross proceeds of \$87.8 million.

WHITESANDS THAI™ Project

Petrobank's 84 percent-owned subsidiary, WHITESANDS Insitu Ltd. ("WHITESANDS") owns a total of 62 sections or 39,680 acres of oil sands leases. WHITESANDS is operating the first field demonstration of Petrobank's THAI™ technology, in the Athabasca oil sands near Conklin, Alberta on a small portion of the WHITESANDS leases. The WHITESANDS THAI™ project consists of three well pairs designed to produce 1,800 barrels per day ("bpd") of bitumen once the project is operating at full capacity. At year-end, two of the three well pairs were producing with the final well pair expected to start producing by the end of the first quarter of 2007. Gross fluid production rates, on a restricted choke, from the first two wells pairs at the WHITESANDS site have been up to 1,000 bpd each with oil cuts ranging between 30 and 50 percent. These restricted rates are necessary at this time to manage sand production and higher than anticipated fluid rates until we complete planned debottlenecking of the plant to allow the wells to produce at their higher capability. To-date, plant operations have experienced frequent down time due to modifications to the sand handling equipment, turnaround of the vent gas sweetening unit as well as periods of very cold weather in the first quarter of 2007. We are still in the early stages of the THAI™ process and in a state of continual adjustment of our operations. This continuous improvement process is consistent with starting up

the first field scale demonstration of a new technology, allowing us to modify, on a controlled basis, the surface facilities and operating procedures. We foresee an ongoing process of technical improvement and innovation as we enhance our ability to produce oil using THAI™. The Company expects to reach the designed capacity of 1,800 bpd of bitumen production during 2007 and with planned facility modifications, further production increases are anticipated.

The next step is to expand WHITESANDS production up to a planned 10,000 bpd. Initially, plans are to debottleneck the current processing facilities and drill up to three additional well pairs that will incorporate the Company's CAPRI™ technology enhancement later in 2007. Assuming facility expansion and the drilling of new well pairs are approved as expected, the Company could commence construction of the 10,000 bpd project by the end of 2008. Capital expenditures for the plant expansion and related facilities, drilling new well pairs and further resource definition activities to achieve the 10,000 bpd target are estimated to cost approximately \$200 million.

In 2006, the Company invested \$29.8 million focused on completing the construction of the WHITESANDS project. The Company incurred an additional \$28.6 million on oil sands activities not directly related to the project, including acquiring a total of 13 sections of oil sands leases, acquiring and evaluating 3-D seismic data and drilling additional resource delineation wells. Remaining costs of the 1,800 bpd project predominantly include operating costs.

Results of Operations

Revenue

Oil and natural gas revenue increased by 52 percent to \$99.2 million in 2006 from \$65.1 million in 2005. These increases were a result of higher oil and natural gas production in Canada, higher oil production in Colombia and higher realized oil prices in both Canada and Colombia, offset somewhat by lower realized natural gas prices in Canada.

Average Daily Production

	Q4 2006	2006	2005
Canada – light / medium oil and NGL (bbls)	1,195	814	437
Canada – conventional heavy oil (bbls)	70	104	15
Canada – natural gas (mcf)	11,968	12,940	11,810
Total Canada (boe)	3,260	3,075	2,420
Colombia – light / medium oil (tbls)	2,372	2,194	1,031
Total Company (boe)	5,632	5,269	3,451

Total production for the Company increased by 53 percent to 5,269 boe per day ("boepd") in 2006 compared to 3,451 boepd in 2005, comprised of 3,075 boepd of conventional oil and gas production in Canada and 2,194 boepd in Colombia. Bitumen volumes are excluded from average daily production as WHITESANDS operations are considered to be in the development stage and accordingly revenues are offset against capitalized costs as opposed to recognized in net income.

The Company's Canadian production increased by 27 percent to 3,075 boepd from 2,420 boepd in 2005. Natural gas production increased to an average of 12.9 million cubic feet per day ("mmcfpd") compared to 11.8 mmcfpd in 2005. The increase is mainly a result of significant production additions at Jumpbush at the end of 2005, however, since then natural gas production has experienced natural declines, and production additions related to the 2006 drilling program were delayed until late in 2006 and early 2007. Oil and NGL production in Canada averaged 918 bopd during 2006, more than double the 2005 production level. Canadian production in 2006 includes 453 boepd (2005 – 322 boepd) of royalty income production from the Company's fee title lands. The increase in oil and royalty income production through the year relates primarily to new Bakken and Torquay light oil production in southeast Saskatchewan and southwest Manitoba. Canadian production during January and February of 2007 has increased to an average of 4,192 boepd due to natural gas tie-ins late in 2006 and new Bakken and Torquay light oil production. The Company is planning to drill 48 wells in southeast Saskatchewan in 2007, which is expected to result in further working interest oil production increases throughout 2007.

Colombian oil production more than doubled to 2,194 bopd in 2006 from 1,031 bopd in 2005. Production increased 148 percent to 2,372 bopd in the fourth quarter of 2006 compared to 955 bopd in the same period of 2005. The significant increases in 2006 were due mainly to production commencing from the Orito-117 and 118 wells late in the first quarter of 2006, and successful workovers at Orito and Neiva. The Company's ongoing development programs at Orito and Neiva are expected to result in further production additions in 2007.

Average Benchmark Prices

	Q4 2006	2006	2005
WTI crude oil (US\$/bbl)	60.17	66.25	56.70
WTI crude oil (Cdn\$/bbl)	68.54	75.08	68.56
AECO natural gas (Cdn\$/mcf)	6.89	6.51	8.73
US\$/Cdn\$ exchange rate	0.88	0.88	0.83

Realized Prices

The average natural gas price received in 2006 was \$6.21 per mcf, a 23 percent decrease from the \$8.09 per mcf received in 2005. The decrease is primarily a result of lower natural gas benchmark prices. Approximately 16 percent of natural gas production in 2006 (2005 - 18 percent) was sold under the Company's long-term physical natural gas sales contract at a price of \$3.72 per mcf. The price received pursuant to this contract (2,209 GJ per day) was increased to \$4.76 per GJ effective January 1, 2007.

The average Canadian oil and NGL price per barrel received in 2006 was \$61.18, comparable to the 2005 price of \$60.96. Canadian oil and NGL prices represented a US\$12.25 (18 percent of WTI) per barrel discount to the average WTI price in 2006 compared to US\$6.86 (12 percent of WTI) per barrel in 2005. The average discount increased as a result of more heavy oil production increasing the negative impact of Canadian heavy crude oil differentials. The discount is expected to decrease significantly as more Bakken and Torquay light oil production is added in 2007.

Oil sales prices in Colombia averaged US\$54.54 per barrel in 2006, 23 percent higher than the 2005 average of US\$44.30 per barrel. In 2006, the average discount to WTI was US\$11.71 (18 percent of WTI) per barrel, compared to the discount of US\$12.40 (22 percent of WTI) per barrel in 2005. In December the Company negotiated a new sales contract for Orito production resulting in an increase in realized prices relative to WTI. Orito accounted for the majority of Colombian production in 2006 and in the first month of this new sales contract, realized prices for Orito production represented a US\$7.04 (11 percent of WTI) discount to WTI.

Royalties

Consolidated royalty expense remained consistent at \$11.0 million in 2006 compared to \$10.9 million in 2005. Canadian royalties as a percentage of revenue fell to 14 percent in 2006 compared to 21 percent in 2005. The decrease is mainly a result of higher royalty income production from the Company's fee title lands which have no associated royalty expense. Colombian royalties remain constant at a rate of eight percent until the Company's net production per field exceeds 5,000 bopd.

Production Expenses

Consolidated production expenses increased by 57 percent to \$14.0 million in 2006 from \$8.9 million in 2005. Production expenses per unit of production in Canada were \$6.89 per boe in 2006, a 14 percent increase from \$6.05 per boe in 2005. The increase is in part due to increased water handling costs at Red Willow and increases in higher cost conventional heavy oil production.

Production expenses in Colombia averaged \$7.78 per barrel during 2006, an 18 percent decrease from the 2005 average of \$9.49 per barrel. Ecopetrol, the state oil company and our partner, is responsible for primary production operations at Orito and Neiva at a fixed operating fee of US\$4.14 per barrel and US\$2.25 per barrel respectively. The Company's remaining production expenses are primarily fixed, which results in lower production costs per barrel as production increases.

General and Administrative Expenses

Consolidated general and administrative expenses increased by 14 percent in 2006 to \$8.7 million from \$7.6 million in 2005. In Canada, general and administrative expenses decreased by eight percent to \$3.9 million from \$4.2 million a year earlier. In Colombia, the costs increased 42 percent to \$4.9 million from \$3.5 million in 2005 due to costs associated with operating a publicly-owned entity.

Stock-Based Compensation

Stock-based compensation expense increased to \$3.5 million in 2006 from \$1.2 million in 2005. The calculation of this non-cash expense is determined based on the fair value of stock options and deferred common shares granted by both Petrobank and Petrominerales. At higher common share prices the calculated fair value of new grants increases along with the corresponding stock-based compensation expense. In 2006, \$0.6 million of this expense was attributable to Petrominerales stock options granted during the year.

Interest Expense

Interest expense decreased by 65 percent to \$2.9 million from \$8.4 million in 2005. Commencing in the second quarter of 2006 the Company began capitalizing interest in relation to the WHITESANDS project and on July 31, 2006 the Company repaid all outstanding subordinated notes, both of which resulted in lower interest expense.

Depletion, Depreciation and Accretion

Consolidated depletion, depreciation and accretion expense increased to \$30.9 million in 2006 from \$16.4 million in 2005. On a unit-of-production basis, the Canadian rate was \$14.69 per boe compared to \$10.65 per boe a year earlier. The rate increased due to a significant 2006 capital program, the results of which are not fully reflected in the year-end reserve estimates, plus decreases in natural gas reserves, the combined effect of which was reflected in the fourth quarter. The rate in Colombia decreased slightly to \$18.05 per barrel from \$18.53 per barrel in the prior year due to reserve additions primarily at Orito.

Income Applicable to Non-Controlling Interests

The income applicable to non-controlling interests totalled \$1.7 million in 2006 compared to \$nil in 2005 due to the IPO of Petrominerales. The 2006 amount represents the 19.3 percent non-controlling interest in Petrominerales' income from June 29, 2006 until the end of the year.

Taxes

Tax expense of \$2.3 million in 2006 was higher than the \$2.0 million incurred a year earlier. Taxes consist primarily of presumptive income taxes in Colombia which are based on equity capitalization levels. Presumptive income taxes paid in excess of ordinary income taxes owing can be recovered against income taxes in future periods, and can be carried forward for five years. An external reserve evaluation effective December 31, 2006, does not anticipate an ordinary cash income tax liability in Canada in the next three years. A similar external reserve evaluation anticipates an ordinary cash income tax liability in Colombia commencing in 2008. The Company estimates the tax liability in Colombia to be delayed until at least 2009 due to additional exploration expenditures beyond what is reflected in the external reserve evaluation.

Future Income Taxes

The Company recorded a \$0.5 million future income tax expense in 2006 compared to \$0.6 million in 2005. Despite a large increase in net income during the year, the Company recorded a smaller future income expense due to the reduction in future federal and provincial income tax rates in Canada enacted during the year. The future income tax liability on the consolidated balance sheets is also reduced by investment tax credits earned on scientific research and development expenditures related to the WHITESANDS THAI™ project. The Company currently has an unrecognized future income tax asset in Colombia. Accordingly, no future income tax expense is recorded on Colombian income.

Net Income

Net income increased by 80 percent to \$23.1 million from \$12.8 million in 2005. On a per diluted share basis, net income increased to \$0.33 in 2006 from \$0.21 in 2005. Profitability increased mainly due to higher production and realized oil prices, capitalized interest, lower interest expense, lower royalties in Canada and lower future income taxes, partially offset by lower natural gas prices, higher production expenses, general and administrative expenses, stock-based compensation costs, depletion, depreciation and accretion and income applicable to non-controlling interests.

Funds Flow From Operations

The Company's funds flow from operations more than doubled to \$61.4 million in 2006 from \$29.2 million in 2005. On a per diluted share basis, funds flow increased by 82 percent to \$0.89 from \$0.49 a year earlier. The increase is due mainly to higher production, higher realized oil prices and lower per barrel operating costs in Colombia, combined with lower interest expense, partially offset by lower realized natural gas prices.

Capital Expenditures

Years ended December 31,	2006	2005
Business Unit		
Canada	\$ 88,033	\$ 47,087
Latin America (Petrominerales)	83,223	38,424
Heavy Oil	58,437	32,641
Total	\$ 229,693	\$ 118,152

Canadian Business Unit expenditures were spread amongst drilling, completions, workovers and land acquisitions primarily at the Company's Jumpbush, Red Willow and southeast Saskatchewan light oil properties during 2006. The Company's Latin American Business Unit expenditures related to drilling and workovers at Orito, first phase work commitments including drilling a well at Joropo, acquiring and evaluating seismic data on the Company's exploration blocks and workovers at Neiva. The Heavy Oil Business Unit expenditures include the completion of facilities construction and the drilling and completion of well pairs at the Company's WHITESANDS THAI™ project (\$29.8 million), acquiring additional oil sands leases (\$20.5 million), capitalized interest (\$3.4 million), seismic acquisition (\$2.4 million) and resource delineation drilling (\$2.3 million). Currently, WHITESANDS operations are considered to be in the development stage and as a result, operating expenses in excess of revenues are capitalized. To date, Petrobank has received \$8.1 million of the committed \$9.0 million in assistance from Technology Partnerships Canada ("TPC") reflected as a reduction in capital assets in the Company's consolidated financial statements. TPC's mandate is to provide funding support for strategic research and development, and demonstration projects that will produce economic, social and environmental benefits to Canadians.

SUMMARY OF QUARTERLY RESULTS

	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial (\$000s except where noted)								
Oil and natural gas revenue	25,729	24,639	27,267	21,593	22,510	17,983	13,206	11,382
Funds flow from operations ⁽¹⁾	16,057	14,788	19,032	11,548	12,304	8,877	4,575	3,396
Per share – basic (\$)	0.24	0.22	0.28	0.18	0.20	0.15	0.08	0.06
– diluted (\$)	0.23	0.21	0.27	0.17	0.19	0.15	0.08	0.06
Net income (loss)	2,620	5,169	12,075	3,242	5,184	3,170	4,702	(248)
Per share – basic (\$)	0.04	0.08	0.18	0.05	0.08	0.05	0.08	–
– diluted (\$)	0.04	0.07	0.17	0.05	0.08	0.05	0.08	–
Capital expenditures	71,337	57,904	32,935	67,517	58,436	32,094	16,842	10,780
Operations								
Canadian operating netbacks by product ⁽²⁾								
Light/medium oil and NGL sales price (\$/bbl)	55.89	73.88	71.55	60.76	63.46	66.45	63.60	47.59
Royalties	5.55	10.92	11.34	11.56	13.82	14.12	13.94	9.76
Production expenses	10.16	13.08	9.15	5.41	7.92	7.05	10.82	9.99
Operating netback	40.18	49.88	51.06	43.79	41.72	45.28	38.84	27.84
Heavy oil sales price (\$/bbl)	36.79	53.87	50.53	25.37	31.10	52.14	–	–
Royalties	0.89	1.32	1.22	0.68	0.72	0.91	–	–
Production expenses	28.74	29.14	17.25	9.60	15.28	5.95	–	–
Operating netback	7.16	23.41	32.06	15.09	15.10	45.28	–	–
Natural gas sales price (\$/mcf) ⁽³⁾	6.15	5.39	5.84	7.13	10.36	8.25	6.60	6.08
Royalties	0.66	0.71	0.80	1.33	2.15	1.60	1.45	1.19
Production expenses	1.01	1.02	0.84	0.74	0.70	0.91	1.10	1.02
Transportation expenses	0.07	0.10	0.10	0.10	0.11	0.23	0.21	0.29
Operating netback	4.41	3.56	4.10	4.96	7.40	5.51	3.84	3.58
Oil equivalent sales price (\$/boe)	43.86	44.28	43.86	45.51	62.21	53.07	42.63	38.30
Royalties	4.47	6.00	6.13	8.32	13.00	10.41	9.35	7.59
Production expenses	8.06	8.63	6.46	4.89	5.07	5.81	7.12	6.76
Transportation expenses	0.27	0.42	0.43	0.46	0.53	1.08	1.13	1.43
Operating netback	31.06	29.23	30.84	31.84	43.61	35.77	25.03	22.52
Colombian operating netback (\$/bbl)								
Oil sales price	57.68	64.58	64.05	59.03	52.50	60.24	52.34	49.13
Royalties	4.61	5.16	5.17	4.72	4.20	4.82	4.19	3.93
Production expenses	8.39	7.80	6.26	9.66	10.08	9.41	10.09	8.46
Operating netback	44.68	51.62	52.62	44.65	38.22	46.01	38.06	36.74
Average daily production								
Canada – light/medium oil and NGL (bbls)	1,195	690	678	689	639	514	273	317
Canada – heavy oil (bbls)	70	66	119	164	23	37	–	–
Canada – natural gas (mcf)	11,968	10,578	13,322	15,960	14,792	11,485	11,245	9,662
Total Canada (boe)	3,260	2,519	3,017	3,513	3,127	2,465	2,147	1,927
Colombia – oil (bbls)	2,372	2,420	2,612	1,356	955	1,073	1,024	1,072
Total Company (boe)	5,632	4,939	5,629	4,869	4,082	3,538	3,171	2,999

(1) Calculated based on cash flow before changes in non-cash working capital and asset retirement obligations settled.

(2) Six mcf of natural gas is converted to one boe. Bitumen volumes are excluded from average daily production as WHITESANDS operations are considered to be in the development stage and accordingly revenues are offset against capitalized costs.

(3) Canadian sales prices are shown after transportation and forward gas sales contracts.

Significant factors influencing quarterly results were:

- Sold a 16 percent interest in WHITESANDS Insitu Ltd. and recorded a pre-tax gain of \$4.7 million in the second quarter of 2005.
- Completion of the Orito-117 and 118 wells in Colombia late in the first quarter of 2006 resulting in a substantial increase in production.
- On June 29, 2006 the Company completed the IPO of Petrominerales, raising gross proceeds of \$68.6 million.
- The increase in Colombian oil production in the second quarter of 2006 combined with high world oil prices resulted in an increase in net income and funds flow from operations.
- Canadian production increased successively in each quarter during 2005 and into the first quarter of 2006. These increases were primarily a result of development drilling and facilities expansion at Jumpbush. Since then natural gas production has experienced natural declines, and production additions related to the 2006 drilling program were delayed until late in 2006 and early 2007.
- Lower commodity prices in the fourth quarter of 2006 resulted in lower realized prices; offset somewhat by increased light oil production and lower royalties in Canada.
- The Company repurchased \$50.5 million, or approximately 50 percent, of the outstanding face value of the subordinated notes in 2005, and the remaining \$49.9 million balance was repaid upon maturity on July 31, 2006 resulting in lower interest expense.

Commitments

The following is a summary of the Company's remaining contractual commitments at December 31, 2006:

Type of Obligation (000s)	Total	< 1 Year	1-3 Years	4-5 Years
Colombian exploration contracts (US\$)	25,900	16,400	9,500	-
Drilling rigs in Colombia (US\$) ⁽¹⁾	29,000	26,000	3,000	-
WHITESANDS compressor lease (US\$)	2,023	419	837	767
Drilling rigs in Canada (\$)	7,028	4,728	2,300	-
Office operating leases (\$)	2,508	1,037	1,261	210
Total (\$) ⁽²⁾	75,726	55,555	19,069	1,102

(1) The contracted drilling rigs will be used to satisfy a significant portion of the commitments on the exploration contracts.

(2) US\$ amounts have been converted using a US\$/Cdn\$ exchange rate of 0.86.

The Company's 80.7 percent owned subsidiary, Petrominerales, has committed to various work programs pursuant to its exploration contracts in Colombia totalling US\$25.9 million that are required to be completed by June 30, 2008. The work commitments represent normal course exploration expenditures including acquiring and evaluating seismic data and drilling exploration wells. In addition, the Company has secured drilling rigs in Colombia with contract terms extending until March 31, 2008. At year-end 2006, the remaining drilling rig commitments totalled US\$29.0 million, a significant portion of which will be used to satisfy commitments on the exploration contracts. Petrominerales has issued letters of credit totalling US\$3.1 million in connection with the exploration contracts in Colombia and as guarantees to third parties for outstanding contractual obligations.

The Company has also secured a drilling rig until September 30, 2008 to facilitate the southeast Saskatchewan drilling program. As at December 31, 2006, the Company had commitments of \$7.0 million remaining under the terms of the contract.

The Company is committed to spend US\$2.0 million until the end of 2011 for air compression rental at the WHITESANDS project.

Liquidity and Capital Resources

During the year the Company completed the following share issuances:

Date Of Issue	Number Issued	Price Per Share	Gross Proceeds	Use Of Proceeds
February 6, 2006	2,597,403	\$12.85	\$33.4 million	Funded a portion of the 2006 capital program
December 22, 2006	3,000,000	\$17.75	\$53.3 million	Initially repaid \$70 million bridge loan and reduced other bank debt
December 22, 2006	1,500,000 ⁽¹⁾	\$23.00	\$34.5 million	

(1) The Company issued flow-through shares, the proceeds of which were initially used to repay outstanding credit facilities. The Company will renounce the proceeds as resource expenditures to flow-through share investors effective December 31, 2006. The Company has until December 31, 2007 to incur those expenditures, which will be funded with available cash and credit facilities.

The number of Petrobank common shares outstanding as at March 12, 2007 remains unchanged from December 31, 2006 at 72,125,274.

At December 31, 2006 net debt totalled \$40.5 million. The Company had cash and cash equivalents of \$36.4 million relating to Petrominerales, offset by bank debt incurred in relation to the Canadian operations of \$31.8 million. In February 2007, the Company amended its existing Canadian secured credit facilities with a syndicate of banks increasing the combined borrowing limit of the facilities to \$80 million from the previous limit of \$50 million. The amended facilities are comprised of a \$50 million reserve-based revolver and a \$30 million oil sands resource-based revolver, with initial terms ending on July 27, 2007, extendable by the lenders for an additional year. If the lenders decide not to extend the term, the drawn amounts become due within one year from the extension date. The \$50 million facility bears interest at rates between LIBOR (London InterBank Offered Rate) and LIBOR plus 1.1 percent depending on debt-to-EBITDA (earnings before interest, taxes, depreciation, and amortization) levels. The \$30 million facility bears interest at LIBOR plus 2.5 percent. The facilities are secured by a \$300 million demand debenture and a securities pledge on the Company's subsidiaries with ownership of WHITESANDS and the THAI™ technology.

The lenders of the Canadian facilities periodically, and at least annually, assess the amount of the borrowing bases available, which determines how much the Company can draw under each of the two facilities. The borrowing bases are determined according to a number of factors, primarily the commodity price outlook of the lenders, the quantity of the Company's Canadian conventional proved producing and proved undeveloped reserves, the future production profile, the estimated quantity of recoverable bitumen resource and the estimated value of the oil sands leases.

Petrominerales closed a credit facility in relation to its Colombian operations with an international bank on December 20, 2006 for a US\$50 million revolving credit facility with an initial US\$25 million borrowing base and three-year term. The facility bears interest at a rate equal to LIBOR plus three percent per annum. There is no amount currently drawn on this facility which is secured by a pledge over all property of Petrominerales. The borrowing base is reviewed semi-annually.

Petrominerales also maintains a US\$3.1 million operating line of credit in Colombia under which the Company can borrow at the fixed term deposit rate set by the Central Bank of Colombia plus six percent. Advances under the facility are collateralized by a promissory note provided by the Company.

The Company's working capital requirements fluctuate primarily due to capital expenditure activity and oil and gas revenues. Typically, the Company settles its vendor liabilities following collection of oil and gas revenues.

In addition to the credit facilities and operating line of credit previously mentioned, other possible sources of funds available to Petrobank include the following:

- Funds flow from operations, which is expected to continue to increase with anticipated increases in production.
- Government incentive programs such as the Government of Alberta's Innovation Energy Technologies Program may be available to fund a portion of the WHITESANDS THAI™ project costs and potentially costs associated with testing the Company's related CAPRI™ technology.
- Project financing attributable to the WHITESANDS expansion project.
- Issuance of subordinated debt.
- Petrobank may issue common shares in Canada or Norway, with or without flow-through tax benefits. In Canada, flow-through shares allow the Company to pass the deductibility of certain oil and natural gas expenditures through to subscribers. Typically, these shares attract a premium to existing market prices, but the amount that can be raised is limited to exploration expenditures incurred in Canada within a 12-24 month period following the issue.
- Petrobank may sell producing or non-producing assets to raise funds in the short term. Incremental cash resources generated as a result would be reduced by any resulting decreases in future cash flows and the borrowing bases under Petrobank's secured credit facilities.
- An alternative financing vehicle is pre-export financing or a pre-sale of a portion of future oil production in Colombia. Petrominerales' Orito and Neiva contracts specifically permit the export of oil and there is no requirement for such proceeds to be remitted to Colombia.
- Petrobank has the option to sell all or a portion of its remaining shareholdings in Petrominerales in the secondary market to generate funds required for other projects. In addition, Petrominerales could raise additional funds through the issuance of additional common shares.

The Canadian Business Unit's capital plan is focused on exploration and development of Petrobank's Bakken and Torquay light oil properties, development of the Jumbush shallow gas property, exploitation of partially matured areas such as Red Willow, high impact exploration in northwest Alberta, and leveraging the Company's significant undeveloped land base into new opportunities. Success will enhance the Company's cash position and borrowing capacity under its secured credit facilities. In addition to conventional opportunities, the Canadian Business Unit has coalbed methane ("CBM") potential at both its Jumbush and Princeton properties. The Princeton project requires more upfront capital than Jumbush because of its location and the nature of the reservoir. The CBM projects will be more difficult to finance with conventional debt until they have been proven commercial.

Latin American activity will focus on continuing to develop the potential of the Orito block by drilling up to 10 wells in 2007, drilling up to six wells at Neiva, continuing to acquire and evaluate seismic data and drilling five exploration wells in 2007. Success will enhance Petrominerales' cash position and borrowing capacity under its secured credit facility.

Heavy Oil activity in 2007 will focus on debottlenecking and optimizing operations at the WHITESANDS THAI™ project, scoping and engineering to expand the project to 10,000 bpd, drilling up to three additional well pairs that will incorporate the Company's CAPRI™ technology later in the year, and additional resource delineation by drilling up to 12 wells on the WHITESANDS oil sands leases. The minority shareholder of WHITESANDS Insitu Ltd. is expected to continue to fund its 16 percent share of continuing project costs and other additional costs associated with WHITESANDS activities. With continued success, a WHITESANDS project expansion to 10,000 bpd would require an additional investment of approximately \$200 million.

Risks and Uncertainties

Petrobank is exposed to a variety of risks, including but not limited to competitive, operational, political, environmental and financial.

The oil and gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and gas properties and oil and gas reserves. The competition for land and resources in western Canada is especially intense. Competitors include companies much larger than Petrobank, with greater access to financial resources. The Company's future success is driven, in large part, by its ability to find and exploit new oil and natural gas reserves at reasonable costs and reinvestment ratios. The process of evaluating prospects and estimating oil and natural gas reserves is complex and subject to significant uncertainty. Actual operating results, including production performance, will vary from those estimated, possibly materially. The Company manages these risks by maintaining a focused asset base with high working interests and by hiring qualified professionals, including independent reserve engineers, with appropriate industry experience.

Petrobank is exposed to a number of operational risks inherent in the industry including accidents, well blowouts, uncontrolled flows and environmental risks. Operational risks are managed using prudent field operating procedures. The Company has a detailed emergency response plan to deal with potential incidents and maintains a comprehensive insurance program to reduce the risk of significant economic loss; however, not all risks can be eliminated. Losses resulting from the occurrence of these risks could have a material adverse impact on the Company's operations.

Petrobank currently has operations in Canada and Colombia and is evaluating additional projects internationally. To help mitigate the risks associated with operating in foreign jurisdictions, the Company seeks to operate in regions where the petroleum industry is a key component of the economy. Petrobank believes that management's experience operating both domestically and internationally helps reduce these risks. Some countries in which the Company may operate may be considered politically and economically unstable. In Colombia, the government has a long history of democracy and an established legal framework that, in Petrobank's opinion, minimize political risks.

Colombia has a publicized history of security problems associated with certain narco-terrorist groups. The Company and its personnel are subject to these risks, but through security and social programs, Petrobank believes these risks can be effectively managed. It is difficult to obtain insurance coverage to protect against terrorist incidents and as a result the Company's insurance program excludes this coverage. Consequently, incidents like this in the future could have a material adverse impact on the Company's operations.

The Company's WHITESANDS THAI™ project entails risks incremental to those of conventional oil and gas operations. Although other operators have utilized the individual processes involved in the THAI™ technology in the past, the technology's configuration of wells and processes is a new combination, and thus Petrobank is subject to unknown operational risks. Other risks associated with the project include: the THAI™ technology will prove unsuccessful or commercially unviable; and, unknown future regulatory or commodity market factors will make the technology uneconomic. However, management believes that the technology, can be a step change in heavy oil recovery and would address many of the existing risks and economic challenges currently facing the oil sands industry in Canada as well as international heavy oil development.

The Company is subject to extensive governmental and environmental regulations in its operating jurisdictions. Changes to these regulations, including the implementation of the Kyoto Protocol, could increase the costs of conducting business in these jurisdictions. Environmental risks inherent in the oil and gas industry are subject to increasingly stringent legislation and regulation. The Company operates in accordance with all relevant environmental legislation and strives to minimize the environmental impact of its operations by providing for safety and environmental issues in all of its business plans. In addition, the THAI™ technology has the potential to greatly reduce the environmental impact of the oil sands industry.

Petrobank is exposed to normal financial risks inherent within the oil and gas industry, including commodity price risk, exchange rate risk, interest rate risk and credit risk. Management believes it is neither appropriate nor possible to eliminate 100 percent of the Company's exposure to these risks. As described in Note 14 to the consolidated financial statements, the Company monitors market conditions and may periodically utilize derivative instruments to manage some of these risks.

Commodity prices are the Company's most significant financial risk. Crude oil prices are influenced by global supply and demand, OPEC policy and worldwide political events. Natural gas prices in Canada are influenced primarily by North American supply and demand and to a lesser extent by local market conditions. Weather events and conditions also play a major role in the supply and demand of both commodities. Fluctuations in commodity prices not only affect the Company's cash flows, but may also result in changes to the borrowing capacity under Petrobank's credit facilities as assessed by the Company's lenders.

To the extent revenues and expenditures denominated in or strongly linked to the U.S. dollar are not equivalent, the Company is exposed to exchange rate risk. Revenues are largely determined by U.S. dollar reference prices. The Company is not currently using exchange rate derivatives to manage exchange rate risks.

Petrobank is exposed to fluctuations in short-term interest rates on amounts drawn under its floating-rate bank facilities. The Company has not hedged these rates given the need to remain flexible in borrowing and repaying outstanding balances.

In addition to the foregoing risks, readers are directed to the section entitled, "Risk Factors" in the Company's AIF.

Sensitivities

The Company's earnings and cash flow are sensitive to changes in crude oil and natural gas prices, and exchange rates.

The following factors demonstrate the expected impact on annualized cash flow:

		(\$ millions)
Change of:		
Crude oil	US\$1.00/bbl WTI reference price	\$ 2.3
	100 bopd in Canadian production @ US\$55/bbl WTI	\$ 1.7
	100 bopd in Colombian production @ US\$55/bbl WTI	\$ 1.6
Natural gas	\$1.00/mcf AECO reference price	\$ 4.7
	1.0 mmcf per day production @ \$6.50/mmbtu AECO	\$ 2.0
Currency	\$0.01 in exchange rate	\$ 0.9

Critical Accounting Policies and Estimates

The Company's financial statements are prepared in accordance with Canadian GAAP, which require management to make judgments, estimates and assumptions which may have a significant impact on the financial statements. A summary of the Company's significant accounting policies can be found in Note 2 to the consolidated financial statements. The following is a discussion of those accounting policies and estimates that are considered critical in the determination of the Company's financial results.

Capital Assets – Full Cost Accounting

The Company follows the full cost method of accounting as described in Note 2 to the consolidated financial statements. Alternatively, the Company could follow the successful efforts method of accounting whereby all costs related to non-productive wells are expensed in the period in which they are incurred. The full cost method is the method most commonly followed.

Operating costs, net of revenues in relation to activities that are considered to be in the development stage, are capitalized. Judgement is required to determine whether operations are in the development stage. The factors considered include whether commercially viable production levels have been achieved on a consistent basis. Once the operations are no longer considered to be in the development stage, revenue is recognized and operating costs are recorded in net income during the year.

Under the full cost method of accounting, capitalized costs are subject to a country-by-country cost centre impairment test. Under the successful efforts method of accounting, the costs aggregated on a property-by-property basis and the carrying value of each property is subject to an impairment test. These policies may result in a different carrying value for capital assets and a different net income. Under full cost accounting, a limit is placed on the carrying value of the net capitalized costs in each cost centre in order to test impairment. Impairment exists when the carrying value of developed properties of a cost centre exceeds the estimated undiscounted future net cash flows associated with the cost centre's proved reserves. Costs relating to undeveloped properties are subject to individual impairment assessments until it can be determined whether or not proved reserves exist. If impairment is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the cost centre's proved plus probable reserves are charged to income.

Reserve Estimates

Reserve estimates can have a significant impact on net income and the carrying value of capital assets. The process of estimating reserves requires significant judgment based on available geological, geophysical, engineering and economic data, projected rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to interpretation and uncertainty. Reserve estimates impact net income through depletion expense and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income and can impact the carrying amount of capital assets.

Petrobank's lenders also use reserve estimates to assess the borrowing bases under the secured bank credit facilities. Changes to the reserve estimates can result in increases or decreases to the borrowing bases, which may impact the Company's financial position.

Asset Retirement Obligations

The Company recognizes the estimated fair value of future retirement obligations associated with capital assets as a liability. The Company estimates the liability based on the estimated costs to abandon and reclaim its net ownership in tangible long-lived assets such as wells and facilities and the estimated timing of the costs to be incurred in future periods. Actual payments to settle the obligations may differ from estimated amounts.

Future Income Taxes

The Company recognizes a future income tax liability based on estimates of temporary differences between book and tax value of its assets. An estimate is also used for both the timing and tax rate upon reversal of the temporary differences. Actual differences and timing of the reversals may differ from estimates, impacting the future income tax balance and net income.

New Accounting Pronouncements

The Canadian Accounting Standards Board ("AcSB") recently issued Section 1530, Comprehensive Income. Other comprehensive income comprises revenues, expenses, gains and losses that are not recognized in comprehensive income, but are excluded from net income. Unrealized gains and losses on the translation of self-sustaining foreign operations will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard.

This new standard is effective for fiscal years beginning on or after October 1, 2006 and early adoption is permitted. Adoption of this standard as at December 31, 2006 would have resulted in an increase in the accumulated other comprehensive income account of \$7.2 million offset by a decrease to the cumulative translation adjustment account.

In December 2006, the AcSB issued two new sections in relation to financial instruments: Section 3862, Financial Instruments – Disclosures, and Section 3863, Financial Instruments – Presentation. Both sections will become effective for annual and interim periods beginning on or after October 1, 2007 and will require increased disclosure of financial instruments.

In December 2006, the AcSB issued Section 1535, Capital Disclosures, requiring disclosure of information about an entity's capital and the objectives, policies, and processes of managing capital. The standard is effective for annual periods beginning on or after October 1, 2007.

Regulatory Policies

Certification of Disclosures in Annual and Interim Filings

In accordance with Multilateral Instrument 52-109 of the Canadian Securities Administrators, the Company annually issues a "Certification of Annual Filings" ("Certification"). The Certification requires certifying officers to state that they are responsible for establishing and maintaining disclosure controls and procedures, have designed such procedures and evaluated their effectiveness as of the end of the period covered by these annual filings. In addition, the Certification requires certifying officers to state that they have designed such internal control over financial reporting, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. The Company has continually had in place systems relating to internal control over financial reporting and will continue to monitor internal controls as the Company's business evolves.

The certifying officers have evaluated the effectiveness of the Company's disclosure controls and procedures and, based on such evaluation, believe that the disclosure controls and procedures provide a reasonable assurance that information required to be disclosed by the Company in these annual filings is recorded, processed, summarized and reported within the time periods specified and the controls and procedures ensure that the information required to be disclosed by the Company is accumulated and communicated to Petrobank's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Outlook

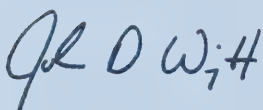
In addition to the plans discussed herein, please see the Company's 2007 Corporate Profile for a discussion of the Company's future business prospects.

MANAGEMENT'S REPORT

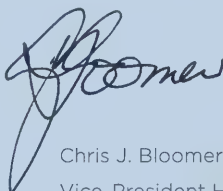
Management is responsible for the integrity and objectivity of the information contained in this report and for the consistency between the consolidated financial statements and other financial and operating data contained elsewhere in this report. The accompanying consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgement, particularly in those circumstances where transactions affecting a current period are dependent upon future events. The accompanying consolidated financial statements have been prepared using policies and procedures established by management and fairly reflect the Company's financial position, results of operations and changes in financial position, within Canadian generally accepted accounting principles. Management has established and maintains a system of internal controls that is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and the financial information is reliable and accurate.

The Company's external auditors, Deloitte & Touche LLP, have examined the consolidated financial statements. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported financial results and the financial condition of the Company.

The Audit Committee of the Board of Directors has reviewed in detail the consolidated financial statements with management and the external auditors. The Board of Directors on the recommendation of the Audit Committee has approved the consolidated financial statements.



John D. Wright
President & Chief Executive Officer
Calgary, Canada
March 9, 2007



Chris J. Bloomer
Vice-President Heavy Oil & Chief Financial Officer

AUDITORS' REPORT

TO THE SHAREHOLDERS OF PETROBANK ENERGY AND RESOURCES LTD.:

We have audited the consolidated balance sheets of Petrobank Energy and Resources Ltd. (the "Company") as at December 31, 2006 and 2005 and the consolidated statements of operations and retained earnings (deficit) and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements presents fairly, in all material respects, the financial position of Petrobank Energy and Resources Ltd. as at December 31, 2006 and 2005 and the results of operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Deloitte & Touche LLP
Chartered Accountants
Calgary, Canada
March 9, 2007

CONSOLIDATED BALANCE SHEETS

(Thousands of Canadian dollars)

As at December 31,	2006	2005
Assets		
Cash and cash equivalents	\$ 36,412	\$ 25,343
Accounts receivable and other current assets	13,547	21,727
	49,959	47,070
Other assets	1,271	-
Capital assets (Note 4)	396,301	213,912
	\$ 447,531	\$ 260,982
Liabilities and Shareholders' Equity		
Accounts payable and accrued liabilities	\$ 58,732	\$ 58,834
Subordinated notes (Note 11)	-	49,044
	58,732	107,878
Bank debt (Note 5)	31,772	-
Obligations under gas sale and transportation contracts (Note 6)	4,823	5,650
Asset retirement obligations (Note 7)	10,520	7,931
Future income tax (Note 9)	3,802	10,358
	109,649	131,817
Non-controlling interests (Note 8)	82,291	8,406
Shareholders' equity		
Common shares (Note 10)	244,022	123,262
Contributed surplus (Note 10)	3,166	1,573
Cumulative translation adjustment (Note 3)	(10,627)	-
Retained earnings (deficit)	19,030	(4,076)
	255,591	120,759
	\$ 447,531	\$ 260,982

Subsequent events (Notes 5 and 12)

Commitments and contingencies (Note 16)

See accompanying notes to these consolidated financial statements.

Signed on behalf of the Board:



James D. Tocher
Chairman



Ian S. Brown
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

(Thousands of Canadian dollars, except per share amounts)

Years ended December 31,	2006	2005
Revenues		
Oil and natural gas	\$ 99,228	\$ 65,081
Interest income	1,068	1,147
Royalties	(11,008)	(10,857)
	89,288	55,371
Expenses		
Production	13,969	8,912
Transportation	439	866
General and administrative	8,746	7,648
Stock-based compensation	3,536	1,168
Interest (Note 13)	2,941	8,429
Foreign exchange loss	228	68
Other	892	235
Depletion, depreciation and accretion	30,940	16,382
	61,691	43,708
Income before other items, taxes and non-controlling interests	27,597	11,663
Gain (Note 8)	-	4,744
Loss on repurchase of subordinated notes (Note 11)	-	(968)
Income before taxes and non-controlling interests	27,597	15,439
Taxes	(2,264)	(2,024)
Future income taxes (Note 9)	(543)	(607)
Income before non-controlling interests	24,790	12,808
Income applicable to non-controlling interests (Note 8)	(1,684)	-
Net income	23,106	12,808
Deficit, beginning of year	(4,076)	(16,884)
Retained earnings (deficit), end of year	\$ 19,030	\$ (4,076)
Earnings per share (Note 10)		
Basic	\$ 0.35	\$ 0.22
Diluted	\$ 0.33	\$ 0.21

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

(Thousands of Canadian dollars)

Years ended December 31,	2006	2005
Operating Activities		
Net income	\$ 23,106	\$ 12,808
Depletion, depreciation and accretion	30,940	16,382
Stock-based compensation (Note 10)	3,536	1,168
Future income taxes (Note 9)	543	607
Amortization of discount on subordinated notes (Note 11)	880	1,963
Loss on repurchase of subordinated notes (Note 11)	-	968
Gain (Note 8)	-	(4,744)
Amortization of deferred financing charges (Note 5)	736	-
Income applicable to non-controlling interests	1,684	-
	61,425	29,152
Asset retirement obligations settled	(431)	(262)
Changes in other non-cash working capital (Note 15)	3,046	(1,003)
	64,040	27,887
Financing Activities		
Issuance of common shares – net of issuance costs (Note 10)	116,980	48,880
Repayment of subordinated notes (Note 11)	(49,924)	-
Issuance of bank debt – net of issuance costs (Note 5)	29,765	-
Equity issued by subsidiaries – net of issuance costs (Note 8)	63,673	12,651
Sale of interest in subsidiary – net of costs (Note 8)	7,929	-
Amortization of obligations under gas sale and transportation contracts (Note 6)	(827)	(827)
Repurchase of subordinated notes (Note 11)	-	(49,749)
Changes in other non-cash working capital (Note 15)	6,921	-
	174,517	10,955
Investing Activities		
Expenditures on capital assets	(229,693)	(118,152)
Changes in other non-cash working capital (Note 15)	1,247	29,144
	(228,446)	(89,008)
Net effect of foreign exchange on cash denominated in foreign currencies	958	-
Net change in cash position	11,069	(50,166)
Cash and cash equivalents, beginning of year	25,343	75,509
Cash and cash equivalents, end of year	\$ 36,412	\$ 25,343
Cash and cash equivalents consist of:		
Cash	\$ 12,684	\$ 11,381
Cash equivalents	\$ 23,728	\$ 13,962

See accompanying notes to these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2006 and 2005

(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts or as otherwise noted)

NOTE 1 – DESCRIPTION OF BUSINESS

Petrobank Energy and Resources Ltd. (the “Company” or “Petrobank”), is a public company listed on the Toronto and Oslo Stock Exchanges and incorporated under the Business Corporations Act (Alberta). Petrobank is engaged in the exploration for and development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the country of Colombia. Petrobank operates projects through three business units. The Canadian Business Unit has conventional oil and gas operations in the Western Canadian Sedimentary Basin focused in southeast Saskatchewan and central Alberta. The Latin American Business Unit operating in Colombia is comprised of a public company listed on the Toronto Stock Exchange, Petrominerales Ltd. (“Petrominerales”, TSX: PMG), 80.7 percent of which is owned by Petrobank. The consolidated financial statements and other financial information of Petrominerales are located on SEDAR at www.sedar.com or at www.petrominerales.com. The Heavy Oil Business Unit holds 62 sections of oil sands leases near Conklin, Alberta and is operating the WHITESANDS project to field-demonstrate Petrobank’s patented THAI™ heavy oil recovery process.

NOTE 2 – SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and include the accounts of the Company and its subsidiaries. Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the consolidated balance sheets as well as the reported amounts of revenues, expenses, and cash flow during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the consolidated financial statements. Actual results could differ materially from estimated amounts.

Amounts recorded for depreciation, depletion and accretion costs and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves that are subject to measurement uncertainty. Stock-based compensation is based upon volatility and expected life estimates that are also subject to measurement uncertainty. Changes in these estimates could materially impact the consolidated financial statements of future periods.

Capital Assets – Oil and Gas

All costs related to the acquisition, exploration and development of oil and natural gas properties are capitalized. Such costs include land and lease acquisition costs, annual charges on non-producing properties, geological and geophysical costs, costs of drilling and equipping productive and non-productive wells, and carrying costs.

Operating costs, net of revenues in relation to the Company’s WHITESANDS project (included in the Heavy Oil Business Unit) are capitalized. Judgement is required to determine whether operations continue to be in the development stage. The factors considered include whether commercially viable production levels have been achieved on a consistent basis. Once the operations are no longer considered to be in the development stage, revenue is recognized and operating costs are recorded in net income during the year. Prior to the commencement of commercial operations, the Company also capitalizes interest costs in relation to its WHITESANDS project.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of more than 20 percent.

Capitalized costs are accumulated in cost centres on a country-by-country basis and are depreciated and depleted using the unit-of-production method based upon estimated proved reserves before royalties as determined by independent engineers. Costs subject to depletion include estimated costs to develop proved reserves and exclude estimated salvage value. Reserve and production volumes of oil and natural gas are converted to common units on the equivalency basis of six mcf to one bbl, reflecting the approximate relative energy content. Costs relating to undeveloped properties are excluded from the depletion base until it is determined whether or not proved reserves exist or if impairment of such costs has occurred. These properties are assessed at least annually to determine whether impairment has occurred.

Depreciation of office equipment is provided at 30 percent using the declining balance method.

A limit is placed on the carrying value of the net capitalized costs in each cost centre in order to test impairment. The Company is required to perform this impairment test at least annually. Impairment exists when the carrying value of a cost centre exceeds the estimated undiscounted future net cash flows associated with the cost centre’s proved reserves. If impairment is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the cost centre’s proved plus probable reserves are charged to income. Reserves are determined pursuant to National Instrument 51-101 “Standards of Disclosure for Oil and Gas Activities”.

The Company does not capitalize general corporate overhead costs.

Asset Retirement Obligations

The Company recognizes the estimated fair value of future retirement obligations associated with capital assets as a liability in the period in which they are incurred, normally when the asset is purchased or developed. The Company estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is applied prospectively. The change in net present value of the future retirement obligations as time passes is expensed as accretion. The asset retirement cost, equal to the fair value of the asset retirement obligations, is capitalized as part of the cost of the related long-lived asset and amortized using the unit-of production method. Actual retirement obligations settled during the period reduce the accumulated obligations.

Non-Controlling Interests

On June 29, 2006 Petrobank completed an initial public offering of the common shares of its indirectly owned subsidiary, Petrominerales, which comprises Petrobank's Latin American Business Unit. After the transaction, Petrobank owns 80.7 percent of Petrominerales, the remaining 19.3 percent of which is reflected on the consolidated balance sheet within non-controlling interests. Petrominerales' earnings or losses are included in the Company's net income and adjusted to reflect the portion attributable to the non-controlling interests. Non-controlling interests also includes a 16 percent interest in the Company's WHITESANDS Insitu Ltd. ("WHITESANDS") subsidiary owned by a third party. WHITESANDS owns the Company's oil sands leases and is operating the first field test of Petrobank's THAI™ technology. Earnings or losses included in the Company's net income are adjusted to reflect the portion attributable to the non-controlling interests. WHITESANDS is considered to be a project in the development stage and accordingly, the majority of expenses net of revenues are being capitalized.

Derivative Financial Instruments

The Company may utilize derivative financial instruments in its management of exposures to fluctuations in crude oil and natural gas prices, foreign currency exchange rates and interest rates. The Company does not enter into derivative financial instruments for trading or speculative purposes. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. Gains and losses on contracts that constitute effective hedges are deferred and recognized in income when the related transactions occur.

Joint Operations

The majority of the Company's oil and natural gas operations are conducted jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

Revenue Recognition

Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized when title passes to the customer.

Foreign Currency Translation

Effective July 1, 2006, the Company translates foreign currency denominated assets and liabilities of its self-sustaining Colombian operations at the exchange rate in effect at the balance sheet date, while revenues and expenses are translated using average monthly rates. Translation gains and losses relating to the self-sustaining Colombian operations are deferred and included in a cumulative translation adjustment account in shareholders' equity.

Previously, the Company's operations in Colombia were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depletion, depreciation and accretion, which were translated on the same basis as the related assets, and gains or losses on translation were recognized in income.

Monetary assets and liabilities denominated in a currency other than a functional currency are translated into its functional currency at the rates of exchange in effect at the period end date. Exchange gains or losses are included in the determination of net income as foreign exchange gain or loss.

Earnings Per Share

The Company computes basic earnings per share using net income divided by the weighted-average number of common shares outstanding. Diluted earnings per share are determined using the same method as basic, except that the weighted-average number of common shares outstanding includes the potential dilutive effect of outstanding stock options and deferred common shares granted by the Company and Petrominerales, as determined by the treasury stock method.

Stock-Based Compensation

The Company accounts for stock-based compensation using the fair-value method of accounting for stock options and deferred common shares (collectively referred to as "Rights") granted to employees, officers and directors using the Black-Scholes option-pricing model. Stock-based compensation expense is recorded and reflected as stock-based compensation expense for Rights granted, whether the Rights are granted by Petrobank or its subsidiary, Petrominerales. The portion of the expense related solely to Petrobank Rights is reflected in contributed surplus and the portion of stock-based compensation expense attributable to Petrominerales is recorded as an adjustment to non-controlling interests (Note 8). Stock-based compensation expense is calculated as the estimated fair value of the related Rights at the time of the grant, amortized over their vesting period. When Rights granted by Petrobank are exercised, the associated amounts previously recorded as contributed surplus are reclassified to common share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

Income Taxes

The Company accounts for income taxes using the liability method. Under this method, the Company records a future income tax asset or liability to reflect any difference between the accounting and tax bases of assets and liabilities. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs. Future income tax assets are only recognized to the extent it is more likely than not that sufficient future taxable income will be available to allow the future income tax asset to be realized.

Subordinated Notes

Interest on the subordinated notes were payable quarterly at a rate of nine percent per annum until maturity on July 31, 2006. The notes were recorded at fair value on issuance and the discount to face value was amortized to interest expense over the term of the notes, creating an effective interest rate of 12 percent.

Government Assistance

The Company records the benefit of government assistance as a reduction in the related capital expenditures as they are incurred and when there is reasonable assurance of collection.

Investment Tax Credits

Investment tax credits arise as a result of incurring qualified scientific research and development expenditures ("SR&ED"), and are recorded as a reduction of the related expenditure or carrying value when there is reasonable assurance of collection.

Flow-Through Common Shares

The Company has financed a portion of its exploration activities in Canada through the issuance of flow-through shares. Under the terms of these shares, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded in the period in which the related tax attributes are renounced.

Cash and Cash Equivalents

Cash and cash equivalents include investments and deposits with a maturity of three months or less when purchased.

NOTE 3 - CHANGE IN ACCOUNTING POLICY

Change in Currency Translation

Following completion of the initial public offering of 19.3 percent of the Company's previously wholly-owned subsidiary, Petrominerales, the Company determined that there was a significant change in its operations in Colombia, and determined that these operations are now self-sustaining. The accounts of the self-sustaining Colombian operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average monthly rates for the period. Translation gains and losses are deferred and included as a separate component of shareholders' equity.

Previously, operations in Colombia were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depletion, depreciation and accretion, which were translated on the same basis as the related assets, and gains or losses on translation were recognized in income.

This change was adopted prospectively on July 1, 2006 and resulted in a currency translation adjustment of \$17.9 million with a corresponding decrease in capital assets. Through the remainder of 2006, a \$7.2 million translation gain was recorded to the currency translation adjustment account.

NOTE 4 - CAPITAL ASSETS

December 31, 2006	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	\$ 247,831	\$ 95,563	\$ 152,268
Heavy Oil	85,976	-	85,976
Colombia	210,698	53,812	156,886
Corporate and other	6,364	5,193	1,171
	\$ 550,869	\$ 154,568	\$ 396,301

December 31, 2005	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	\$ 157,764	\$ 80,220	\$ 77,544
Heavy Oil	35,445	-	35,445
Colombia	138,867	38,759	100,108
Corporate and other	6,113	5,298	815
	\$ 338,189	\$ 124,277	\$ 213,912

At December 31, 2006, oil and natural gas properties included \$116.0 million (2005 - \$44.0 million) relating to unproved properties in Canada, which are primarily costs related to the Company's WHITESANDS project, and \$16.8 million (2005 - \$7.9 million) related to international unproved properties, primarily in Colombia, that have been excluded from the depletion calculation.

An impairment test calculation was performed for each of the Canadian and Colombian cost centres at December 31, 2006 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amounts. In determining the undiscounted future net cash flows for each cost centre, the Company utilized the following benchmark prices:

Year	AECO Natural Gas ⁽¹⁾ - Cdn\$/mcf	WTI Crude Oil ⁽¹⁾ - US\$/bbl
2007	\$ 7.72	\$ 65.73
2008	8.59	68.82
2009	7.74	62.42
2010	7.55	58.37
2011	7.72	55.20
Thereafter inflation % change	1.7% until 2017, 2% thereafter	2%

(1) Actual prices used in the impairment tests were adjusted for price differentials specific to the Company's operations. The US\$/Cdn\$ exchange rate used for all years was 0.87.

NOTE 5 - BANK DEBT

At December 31, 2006, the Company had drawn \$31.8 million (2005 - \$nil) on its secured Canadian credit facilities. In February 2007, the combined borrowing limit of the facilities was increased to \$80 million from the previous limit of \$50 million. The amended facilities are comprised of a \$50 million reserve-based revolver and a \$30 million oil sands resource-based revolver, with initial terms ending on July 27, 2007, extendable by the lenders for an additional year. If the lenders decide not to extend the term, the drawn amounts become due within one year from the extension date. The \$50 million facility bears interest at rates between LIBOR (London InterBank Offered Rate) and LIBOR plus 1.1 percent depending on debt-to-EBITDA (earnings before interest, taxes, depreciation, and amortization) levels. The \$30 million facility bears interest at LIBOR plus 2.5 percent. The facilities are secured by a \$300 million demand debenture and a securities pledge on the Company's subsidiaries with ownership of WHITESANDS and the THAI™ technology.

Petrominerales closed a credit facility in relation to its Colombian operations with an international bank on December 20, 2006 for a US\$50 million revolving credit facility with an initial US\$25 million borrowing base and three-year term. The facility bears interest at a rate equal to LIBOR plus three percent per annum and is secured by a pledge over all property of Petrominerales.

Petrominerales also maintains a US\$3.1 million operating line of credit in Colombia under which the Company can borrow at the fixed term deposit rate set by the Central Bank of Colombia plus six percent. Advances under the facility are collateralized by a promissory note provided by the Company.

During the year the Company incurred \$2.0 million (2005 - \$nil) to secure credit facilities, of which \$0.7 million (2005 - \$nil) was amortized to the income statement and the remainder will be deferred and amortized over the terms of the facilities.

NOTE 6 - OBLIGATIONS UNDER GAS SALE AND TRANSPORTATION CONTRACTS

The Company assumed certain physical natural gas sales and transportation obligations upon the acquisition of Barrington Petroleum Ltd. in 2001. The Company recorded a liability for these obligations at that time, which is being amortized to oil and natural gas revenues over the term of the related contracts (Note 14).

NOTE 7 - ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligations were estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods.

Changes to asset retirement obligations were as follows:

	2006	2005
Asset retirement obligations, beginning of year	\$ 7,931	\$ 2,870
Obligations incurred	1,075	4,674
Obligations settled	(431)	(262)
Accretion expense	657	267
Change in estimated future cash flows and other	1,288	382
Asset retirement obligations, end of year	\$ 10,520	\$ 7,931

The obligations have been calculated using an inflation rate of two percent in Canada and 3.5 percent in Colombia, and discounted using a credit-adjusted risk free rate of eight percent per annum in Canada and 9.5 percent in Colombia. Most of these obligations are not expected to be paid for several years extending up to 30 years in the future in Canada and 15 years in the future in Colombia, and are expected to be funded from general resources of the Company and Petrominerales at their respective settlement dates. The total undiscounted amount of estimated cash flows required to settle the obligations at December 31, 2006 is \$33.4 million (2005 - \$29.7 million) for the obligations in Canada and US\$3.1 million (2005 - US\$2.1 million) for the obligations in Colombia.

NOTE 8 - NON-CONTROLLING INTERESTS

The components of the Company's non-controlling interests are as follows:

	WHITESANDS	Petrominerales	Total
Balance at December 31, 2005	\$ 8,406	\$ -	\$ 8,406
Sale of interest	-	63,482	63,482
Contributed from non-controlling interest	8,119	-	8,119
Attributable income	-	1,684	1,684
Stock-based compensation (Note 2)	-	600	600
Balance at December 31, 2006	\$ 16,525	\$ 65,766	\$ 82,291

WHITESANDS

On April 12, 2005 the Company sold a 16 percent interest in its previously wholly-owned subsidiary, WHITESANDS to an investor for proceeds of \$14.0 million (\$12.7 million net of issuance costs). The reduction in the Company's interest in WHITESANDS resulted in a pre-tax gain of \$4.7 million and a non-controlling interest balance of \$8.4 million. The investor has continued to fund its proportionate share of expenditures on an ongoing basis and contributed an additional \$8.1 million during 2006.

Under the financing agreement, on an annual basis, the investor may request a third-party valuation of WHITESANDS and may require the Company to repurchase the investor's interest in WHITESANDS at fair market value. The Company has the option to fund this repurchase with cash and/or through the exchange of Petrobank common shares, valued at 95 percent of the 10-day weighted average trading price prior to the date of exchange.

Petrominerales Ltd.

On June 29, 2006 Petrobank completed an initial public offering of the common shares of its indirectly owned subsidiary, Petrominerales, on the Toronto Stock Exchange. The offering was comprised of a 16.0 million common share issuance from treasury of Petrominerales for gross proceeds of \$60 million (\$55.6 million net of costs) and a secondary offering of 2.3 million shares held by Petrobank for gross proceeds of \$8.6 million (\$7.9 million net of costs). After June 29, 2006, Petrobank's share of Petrominerales' income and stock-based compensation expense incurred by Petrominerales are also included in non-controlling interests.

NOTE 9 - INCOME TAXES

The provision for income taxes differs from the amount that would have been expected by applying the Canadian expected statutory corporate income tax rates to income before taxes and non-controlling interests. The principal reasons for this difference are as follows:

	2006	2005
Income before taxes and non-controlling interests	\$ 27,597	\$ 15,439
Statutory income tax rate	33.01%	37.90%
Expected tax expense	\$ 9,110	\$ 5,851
Increase (decrease) in income tax provision resulting from:		
Change in valuation allowance	(6,967)	(1,654)
Change in tax rates	(3,635)	(1,490)
Stock-based compensation	1,167	443
Non-deductible expenses	247	-
Non-taxable accretion of subordinated notes	145	372
Resource allowance in excess of Crown charges	65	(620)
Non-taxable accounting gain	-	(1,798)
Change in tax pool estimates and other	411	(497)
Future income tax provision	\$ 543	\$ 607

The components of the Company's future income tax assets and liabilities arising from temporary differences are as follows:

As at December 31,	2006		2005	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Non-capital losses	\$ 15,025	\$ -	\$ 11,738	\$ -
Capital assets	-	24,254	-	15,006
Obligations under gas sale and transportation contracts	1,418	-	1,900	-
Asset retirement obligations	3,117	-	2,455	-
Share issue costs	2,717	-	1,516	-
Investment tax credits	8,797	-	4,137	-
Other	89	-	580	-
	31,163	24,254	22,326	15,006
Valuation allowance	(10,711)	-	(17,678)	-
	\$ 20,452	\$ 24,254	\$ 4,648	\$ 15,006

The Company has reflected its future income tax liability, net of future tax assets and the valuation allowance relating to its Colombian operations, on the consolidated balance sheet.

As at December 31, 2006, non-capital losses totalled \$5.0 million in Canada and expire between 2011 and 2015. In Colombia, non-capital losses totalled US\$23.7 million and expire between 2008 and 2011, and excess presumptive income taxes paid totalled US\$11.3 million, which can be deducted against future ordinary income taxes, expiring in 2008 through 2010.

Based on Colombian tax reforms made effective January 1, 2007, tax losses may be carried forward without limitations to offset taxable income; the presumptive income rate was reduced from six percent to three percent on the prior tax year's net tax equity; the seven percent remittance tax was eliminated; a 1.2 percent equity tax was introduced, the income tax rate was reduced from 38.5 percent to 34 percent in 2007, and to 33 percent for subsequent years; and, the special deduction for the acquisition or construction of real fixed assets was increased to 40 percent from 30 percent.

NOTE 10 – SHARE CAPITAL

Authorized

Unlimited number of common shares

Unlimited number of preferred shares, issuable in series

Common Share Continuity	Number	Amount
Balance at December 31, 2004	54,956,396	\$ 73,157
Exercise of stock options	795,725	1,735
Exercise of warrants	467,600	1,870
April 12, 2005 private placement	3,000,000	9,750
October 20, 2005 private placement	4,000,000	38,600
Share issue costs	-	(3,075)
Tax effect of share issue costs	-	1,105
Transfer from contributed surplus related to stock options exercised	-	120
Balance at December 31, 2005	63,219,721	\$ 123,262
Exercise of stock options	862,450	2,998
Exercise of warrants ⁽¹⁾	945,700	3,783
Issued in connection with secondary listing ⁽²⁾	2,597,403	33,377
Issued in December 2006 ⁽³⁾	4,500,000	87,750
Share issue costs	-	(7,855)
Tax effect of share issue costs	-	2,438
Options settled with cash ⁽⁴⁾	-	(3,074)
Transfer from contributed surplus related to stock options exercised	-	1,343
Balance at December 31, 2006	72,125,274	\$ 244,022

(1) A total of 945,700 share purchase warrants were exercised in the first half of the year before they expired on May 6, 2006, resulting in total cash proceeds of \$3.8 million. There were 7,000 share purchase warrants that expired without being exercised.

(2) On February 6, 2006 the Company closed an issuance of 2.6 million common shares in connection with a secondary listing on the Oslo Stock Exchange for net proceeds of \$30.2 million.

(3) On December 22, 2006 the Company closed an issuance of 3.0 million common shares at a price of \$17.75 per share, and 1.5 million flow-through common shares at a price of \$23.00 per share for gross proceeds of \$87.8 million. The Company will renounce \$34.5 million of resource expenditures to flow-through share investors effective December 31, 2006. The tax effect of those expenditures will be recorded in 2007. The Company has until December 31, 2007 to incur those expenditures.

(4) The Company approved the exercise of certain Petrobank stock options, which were settled with cash for Petrominerales employees who invested in the initial public offering of Petrominerales.

Contributed Surplus

Changes in Contributed Surplus	Amount
Balance at December 31, 2004	\$ 525
Transfer to common shares related to stock options exercised	(120)
Stock-based compensation	1,168
Balance at December 31, 2005	\$ 1,573
Transfer to common shares related to stock options exercised	(1,343)
Stock-based compensation related to Petrobank stock options and deferred common shares	2,936
Balance at December 31, 2006	\$ 3,166

Stock Options

The Company has established a stock option plan whereby the Company may grant options to its directors, officers, employees, consultants and underwriters. The plan allows for the issuance of up to 10 percent of the outstanding common shares of the Company, less shares reserved under other Company stock-based compensation plans such as the deferred share compensation plan. The exercise price of each option is no less than the market price of the Company's stock on the date of the grant. Stock option terms are determined by the Company's Board of Directors but typically, options vest evenly over a period of four years from the date of grant and expire five to 10 years after the date of grant. The following is a continuity of the Company's outstanding stock options:

	2006		2005	
	Stock Options	Weighted-Average Exercise Price	Stock Options	Weighted-Average Exercise Price
Opening	4,138,526	\$ 3.83	3,381,751	\$ 2.47
Granted	1,546,000	15.81	1,809,500	5.48
Exercised	(862,450)	3.48	(795,725)	2.18
Cancelled	(291,126)	11.91	(257,000)	2.64
Settled for cash	(268,563)	4.53	-	-
Closing	4,262,387	\$ 7.65	4,138,526	\$ 3.83

The following summarizes information about stock options outstanding as at December 31, 2006:

Options Outstanding				Exercisable Options	
Range of Exercise Prices (\$)	Number Outstanding	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price	Number Exercisable	Weighted-Average Exercise Price
1.50 – 3.49	1,602,675	1.9	\$ 2.66	992,552	\$ 2.74
3.50 – 6.99	1,039,750	3.3	4.26	224,500	4.18
7.00 – 12.99	331,712	3.8	8.88	54,212	8.94
13.00 – 18.33	1,288,250	7.0	16.29	-	-
	4,262,387	3.9	\$ 7.65	1,271,264	\$ 3.26

Deferred Share Compensation Plan

Petrobank has established a deferred share compensation plan whereby the Company may grant deferred common shares to its directors, officers and employees. As at December 31, 2006, there were 150,500 (2005 – 140,000) deferred common shares outstanding under the plan, which allows holders to receive one common share upon payment of \$0.05 per share. The deferred common shares vest after three years and expire 10 years from the date of grant. Up to 0.5 million deferred common shares have been approved for issuance under this plan.

Stock-Based Compensation

The fair value of Petrobank stock options and deferred common shares granted have been estimated on their respective grant dates using the Black-Scholes option-pricing model using the following assumptions:

Years ended December 31,	2006	2005
Risk free interest rate	4.5%-5%	4.25%-4.5%
Dividend rate	0%	0%
Expected life – options (years)	3.5 - 4	4
Expected life – deferred common shares (years)	8	8
Expected volatility	40%	30%-50%

The average value per stock option and deferred common share granted by the Company during the year ended December 31, 2006 was \$5.32 (2005 – \$2.09) and \$13.97 (2005 – \$4.86) respectively, as at the date of grant. In addition, stock options were granted by Petrominerales, an 80.7 percent owned subsidiary of Petrobank. For the year ended December 31, 2006, the Company's stock-based compensation expense totalled \$3.5 million (2005 – \$1.2 million), of which \$0.6 million (2005 – \$nil) related to Petrominerales.

NOTE 16 - COMMITMENTS AND CONTINGENCIES

The Company has committed to various work programs pursuant to its exploration contracts in Colombia totalling US\$25.9 million that are required to be completed by June 30, 2008. The work commitments represent normal course exploration expenditures including acquiring and evaluating seismic data and drilling exploration wells. In addition, the Company has secured drilling rigs in Colombia with contract terms extending until March 31, 2008. At year-end 2006, the remaining drilling rig commitments totalled US\$29.0 million, a significant portion of which will be used to satisfy commitments on the exploration contracts.

The Company has also secured a drilling rig until September 30, 2008 to facilitate the drilling program targeting the Bakken formation in southeast Saskatchewan. At December 31, 2006, the Company had commitments of \$7.0 million remaining under the terms of the contract.

The Company is committed to spend US\$2.0 million until the end of 2011 for air compression rental at the WHITESANDS project.

Petrobank is committed to payments under operating leases for office space, as follows:

Year	
2007	\$ 1,037
2008	1,261
2009	210
	\$ 2,508

Petrominerales has issued letters of credit totalling US\$3.1 million in connection with its exploration contracts in Colombia and as guarantees to third parties for outstanding contractual obligations.

The development of certain of the Company's assets and the success of its operations are dependent on obtaining sufficient financing to fund its working capital requirements and future capital expenditure commitments. The Company plans to fund these commitments with existing cash balances, funds flow from operations, available credit facilities, new debt and potentially through the issuance of equity.

The Company is party to certain legal actions arising in the normal course of business, the outcome of which cannot be reasonably determined. In the opinion of management, the resolution of these matters will not have a material effect on the Company's financial position or results of operations.

The Company has entered into certain types of contracts, particularly those related to divestiture transactions that require it to indemnify parties against possible third-party claims. These obligations are typically limited to the amount of sales proceeds and expire within one year in the case of property dispositions. Management does not expect payments, if any, related to such matters to have a material effect on the Company's financial position or results of operations.

NOTE 17 – SEGMENTED INFORMATION

Years ended December 31,	2006			2005		
	Canada and Other	Colombia	Total	Canada and Other	Colombia	Total
Revenues						
Oil and natural gas	\$ 49,835	\$ 49,393	\$ 99,228	\$ 44,904	\$ 20,177	\$ 65,081
Interest income	510	558	1,068	1,147	-	1,147
Royalties	(7,047)	(3,961)	(11,008)	(9,243)	(1,614)	(10,857)
	43,298	45,990	89,288	36,808	18,563	55,371
Expenses						
Production	7,736	6,233	13,969	5,341	3,571	8,912
Transportation	439	-	439	866	-	866
General and administrative	3,857	4,889	8,746	4,194	3,454	7,648
Stock-based compensation	2,936	600	3,536	-	-	-
Depletion, depreciation and accretion	16,484	14,456	30,940	9,408	6,974	16,382
Income applicable to non-controlling interests	-	1,684	1,684	-	-	-
Segmented income	\$ 11,846	\$ 18,128	\$ 29,974	\$ 16,999	\$ 4,564	\$ 21,563
Non-segmented expenses						
Stock-based compensation			-			(1,168)
Interest			(2,941)			(8,429)
Foreign exchange loss			(228)			(68)
Other expense			(892)			(235)
Gain			-			4,744
Loss on repurchase of subordinated notes			-			(968)
Taxes			(2,264)			(2,024)
Future income taxes			(543)			(607)
Net income			\$ 23,106			\$ 12,808
Identifiable assets ⁽¹⁾	\$ 253,998	\$ 193,533	\$ 447,531	\$ 157,867	\$ 103,115	\$ 260,982
Capital expenditures ⁽¹⁾	\$ 146,470	\$ 83,223	\$ 229,693	\$ 79,728	\$ 38,424	\$ 118,152

(1) Canada includes Heavy Oil Business Unit expenditures of \$58.4 million in 2006 (2005 – \$32.6 million), identifiable assets at December 31, 2006 of \$86.8 million (2005 – \$48.2 million), and negligible revenues and expenses.

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(2) Member of the Audit Committee

(3) Member of the Reserves Committee

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Calgary, Alberta, Canada

Sproule Associates Limited

Calgary, Alberta, Canada

EXCHANGE LISTINGS

The Toronto Stock Exchange

SYMBOL: **PBG**

Oslo Børs

SYMBOL: **PBG**

Pink Sheets

SYMBOL: **PBEGF**

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ABBREVIATIONS

ANH	National Hydrocarbon Agency (Colombia)
bbl(s)	barrel(s)
bcf	billion cubic feet
boe	barrel of oil equivalent
bopd	barrels of oil per day
boepd	barrels of oil equivalent per day
bpd	barrels per day
CBM	coal bed methane
GJ	Gigajoules
IPC	Incremental Production Contract
IPO	initial public offering
km	kilometres
m	metres
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcfpd	mcf per day
mmbtu	millions of British thermal units
mmcf	million cubic feet
NPV	net present value
NGL	natural gas liquids
P+P	proved + probable
TEA	Technical Evaluation Area
WI	working interest
WTI	West Texas Intermediate

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Forward-Looking Statements

This report contains forward-looking statements that are generally identifiable by terms such as anticipate, believe, budget, intend, estimate, expect, outlook, plan or other similar words, and include future capital investment plans. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; the ability to economically test, develop and utilize the Company's patented technologies, the feasibility of the technologies; and other factors, many of which are beyond the control of the Company. There is no representation by Petrobank that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

BOE conversions are presented at six mcf = one barrel.

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